Westcoast Transmission Company Limited

Annual Report 1983

The Company

Westcoast Transmission Company Limited, a federally incorporated company, is engaged in the gathering, processing and transportation of natural gas. It serves the British Columbia and western United States markets with gas from British Columbia, Alberta, the Yukon Territory and the Northwest Territories.

Through its wholly-owned subsidiary, Westcoast Petroleum Ltd., the Company is engaged in the exploration and the development and production of natural gas and oil in Canada and the United States and through its 45%-owned subsidiary, Pacific Northern Gas Ltd., the Company is engaged in the direct distribution of natural gas to consumers in west-central British Columbia. The Company also owns a 50% interest in Foothills Pipe Lines (Yukon) Ltd. which is responsible for the construction and operation of the Canadian segment of the Alaska Highway Natural Gas Pipeline Project.

Information

This report has been prepared for our shareholders, securities regulatory agencies and the stock exchanges. However, it is hoped it will provide a convenient and useful source of information to members of the public and investors also. We have attempted to provide all basic and practical material relating to Westcoast's operations in 1983. If further information is required we invite you to write to the Secretary of the Company.

Westcoast Transmission Company Limited
1333 West Georgia Street
Vancouver, British Columbia
Canada V6E 3K9

Annual Meeting

The Annual Meeting of the Shareholders of Westcoast Transmission Company Limited will be held in the Columbia Room of the Hotel Vancouver, in the City of Vancouver, British Columbia, on Wednesday, April 25, 1984 at 10 a.m. (Local Time).

Contents

Units of Measure

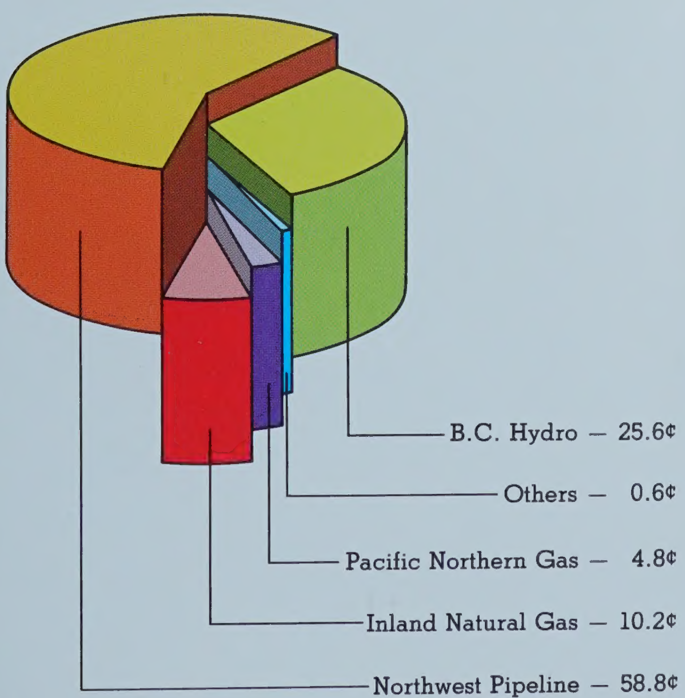
In this Annual Report some units of measure are stated in SI, the official symbol used in all languages for the International System of Units, known to Canadians as the metric system. To assist our shareholders in bridging from standard to metric, the more familiar measures are converted and set out below.

Units	Metric (SI)	Imperial
Volume	1 cubic metre of natural gas (at 101.325 kilopascals and 15°C)	= 35.30 cubic feet of natural gas (at 14.73 pounds per square inch and 60°F)
	10^3m^3 means 1000 cubic metres	Mcf means 1000 cubic feet
		Bcf means billion cubic feet
	1 cubic metre of oil	= 6.2898 barrels
Weight	1 tonne	= 1.10231 tons = 2,204.6 lbs.
Distance	1 kilometre	= 0.6214 miles
Length	1 millimetre	= 0.03937 inches
Area	1 hectare	= 2.471 acres

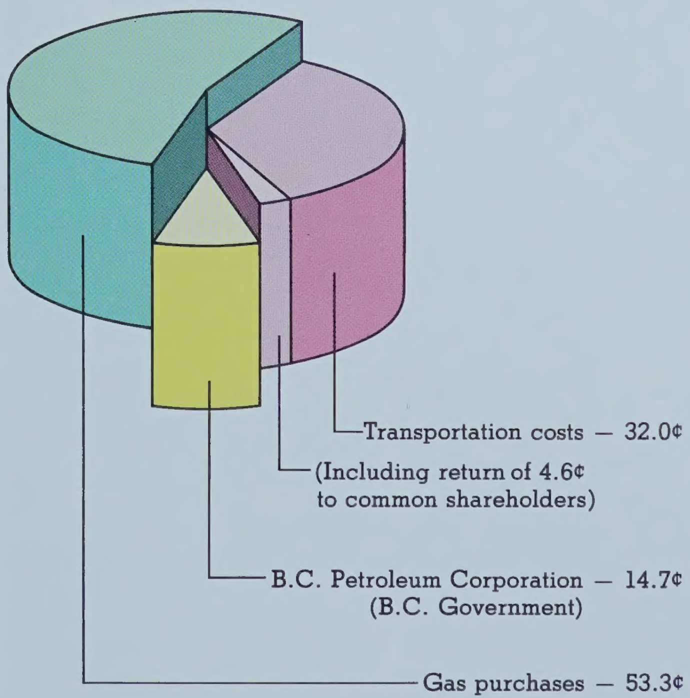
WESTCOAST TRANSMISSION COMPANY LIMITED
RESULTS IN BRIEF FOR THE YEARS ENDED DECEMBER 31

	1983	1982	1981
Financial		(restated)	
Total operating revenues	**$1,127,105,000**	$1,156,951,000	$1,270,330,000
Net income including extraordinary item	**48,444,000**	70,047,000	65,426,000
Net income applicable to common shares:			
Including extraordinary item	**45,302,000**	66,905,000	62,284,000
Before extraordinary item	**61,947,000**	66,905,000	62,284,000
Per common share:			
Including extraordinary item	**1.11**	1.65	1.59
Before extraordinary item	**1.52**	1.65	1.59
Cash flow from operations	**158,875,000**	183,268,000	172,699,000
Total assets	**1,719,052,000**	1,707,913,000	1,480,109,000
Common shareholders' equity	**472,196,000**	470,182,000	445,687,000
per share	**11.59**	11.56	10.97
Common shares — weighted average	**40,721,000**	40,632,000	39,247,000
Operating			
Total gas sales, Mcf	**239,441,163**	249,131,187	278,417,097
Total gas sales, 10^3m^3	**6 782 851**	7 057 348	7 886 955
Average daily sales, Mcf	**656,003**	682,551	762,786
Average daily sales, 10^3m^3	**18 583**	19 335	21 608
Peak day sales, Mcf	**1,534,939**	1,436,622	1,412,614
Peak day sales, 10^3m^3	**43 481**	40 696	40 016

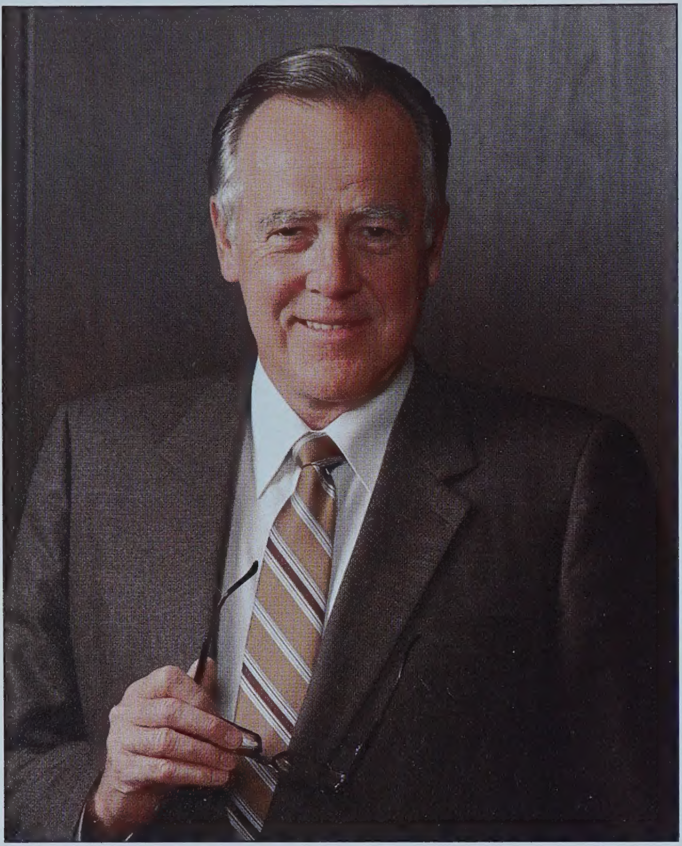
SOURCE OF GAS SALES REVENUE DOLLAR



DISTRIBUTION OF GAS SALES REVENUE DOLLAR



President's Report to Shareholders



In general, 1983's results were mixed. On the positive side, the financial performance of two of the Company's subsidiaries, Westcoast Petroleum Ltd. and Pacific Northern Gas Ltd., showed excellent gains over 1982. On the other hand, the net earnings of the Company were significantly reduced, primarily as the result of two accounting adjustments made to reflect the uncertainties relating to the completion of the Alaska Highway Natural Gas Pipeline Project. Specifically, the extraordinary write-down of certain Phase II or northern segment expenses resulted in a reduction of $16.6 million in net income in the last quarter of the year and our earlier decision, effective January 1, 1983, to cease taking into income a non-cash allowance on funds invested in Phase II further impacted our earnings. Before the extraordinary write-down, net earnings were $65 million compared with $70 million in 1982 and, after provision for preferred share dividends, the net income per common share was $1.52, a decrease from $1.65 in 1982. Consolidated cash flow decreased to $159 million from $183 million in 1982.

The Company's intensive efforts to persuade the authorities to modify the pricing mechanism relating to natural gas exports to the United States in order to improve the volume of such exports met with some success and the export price of Canadian gas was reduced during the year from $4.94 U.S. per MMBtu to $4.40 U.S. per MMBtu. Subsequent to that reduction, a Volume Related Incentive Pricing Plan, which permits discounts for some U.S. customers, was announced by the federal government. However, the Company anticipates that these measures will give rise to only modest increases in gas exports through its pipeline system. The Company will continue its vigorous efforts to increase sales to the export market, and we are confident that, over time, market pricing will be recognized as being the key to a reasonable and healthy level of exports.

Two major projects in which Westcoast hopes to participate are still before the appropriate regulatory authorities. The construction of a natural gas pipeline to and on Vancouver Island has been discussed for several years and a long-awaited public hearing before the British Columbia Utilities Commission on the matter began in late 1983 and will probably conclude in April or May of this year. Should the report favor Westcoast's application to construct the pipeline, a further hearing will be necessary to determine who will build the gas distribution system on Vancouver Island. Pacific Northern Gas Ltd. will be one of the applicants.

Awaiting the outcome of the Vancouver Island Pipeline hearing is the Company's proposal to construct a world-scale fertilizer plant at Powell River, B.C. in concert with Union Oil Company of California, Chieftain Development Co. Ltd. and British Columbia Resources Investment Corporation. Preliminary engineering and design work continues to be performed on the project pending the report and recommendations of the Utilities Commission.

The other major project in which Westcoast hopes to participate is the proposal of Dome Petroleum Limited to sell liquefied natural gas to Japanese customers. Westcoast has applied to the National Energy Board for permission to construct and operate the pipeline facilities required to transport the gas feedstock to the liquefaction plant to be built near Prince Rupert. During 1983, Dome was able to make only limited progress in seeking to secure competitively priced gas supplies for its project and thus more time is required before it can be determined to be a viable project and the regulatory process completed.

For some time now the Company has been reviewing other opportunities for expansion in the energy field and a number of these opportunities will be fully pursued in 1984. It is Westcoast's intention to put in place a dynamic program of business expansion, and action will be taken in this regard irrespective of the outcome of the pending gas utility projects. In this connection, Mr. Michael E. J. Phelps was appointed in July to the position of Vice President, Strategic Planning. Mr. Phelps has had experience in energy matters both with the federal government and private industry.

It was with sadness that we learned of the death on November 8, 1983 of Mr. Norman R. Whittall, a founder and latterly an Honorary Director of the Company. Mr. Whittall made an outstanding contribution to the Company during its formative years.

The Directors extend their thanks to all the employees of the Westcoast group of companies for their continued loyalty and dedication.

John Anderson

John Anderson
President and Chief Executive Officer

Vancouver, British Columbia, Canada
March 22, 1984

Annual Review

One of the Company's natural gas processing plants, located near Chetwynd, is monitored and controlled by a cost-efficient electronic control system.

Financial Review

Financial Results

Consolidated net income for 1983 amounted to $65,089,000 before an extraordinary item. This represents a seven percent decrease from $70,047,000 in the previous year. The extraordinary item, net of deferred income taxes, which amounted to $16,645,000, reduced the 1983 net income to $48,444,000. After the extraordinary item and after provision for preferred dividends, net income per common share decreased to $1.11 from $1.65 a year earlier. Consolidated cash flow from operations decreased to $158,875,000 from $183,268,000 a year earlier. Common share dividends aggregating $1.04 per share were paid during 1983, equalling the dividends paid in 1982.

Because of the continuing uncertainty of the timing of the Alaska Highway Natural Gas Pipeline Project, it has been deemed appropriate to make a provision for certain of the costs of Phase II of the project in the amount of $16,645,000 (net of taxes). This provision is recorded as an extraordinary item.

Contributions to Income

(non-consolidated basis) For the years ended December 31

	1983		1982	
Income from Investments:	**$ millions**	**%**	$ millions	%
Utility Rate Base and Other	**115.1**	**81**	140.7	82
Foothills Pipe Lines (Yukon) Ltd.	**11.8**	**8**	18.1	11
Westcoast Petroleum Ltd.	**12.7**	**9**	10.0	6
Other Subsidiaries	**2.1**	**2**	1.9	1
	141.7	**100**	170.7	100
Deduct:				
Interest and other items	**61.6**		59.0	
Income taxes	**15.0**		41.7	
Net Income*	**65.1**		70.0	

* Before extraordinary item

Contributions to Income

Following a tolls application and hearing in the first half of 1983, the National Energy Board issued its decision in August 1983. Four aspects, in particular, of that decision affected the operating income, cash flow and net income of Westcoast during 1983:

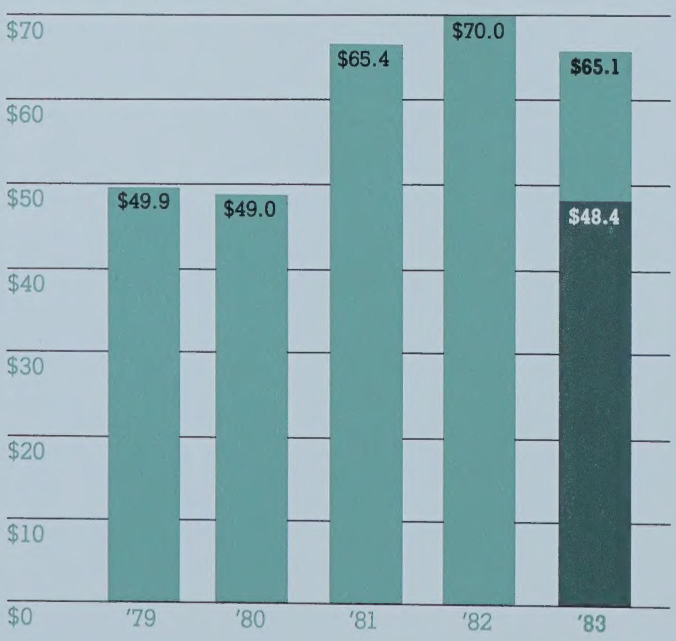
i) A change in the method of collecting income taxes from the normalized to the flow-through basis;
ii) A reduction in the allowed rate of return on common shareholders' equity from 15% to 14.75% per annum;
iii) The transfer from rate base to a deferred account of approximately $24 million pertaining to the costs of replacing defective portions of the Grizzly Valley gathering pipeline system; and
iv) An increase in the rate of return on rate base effective January 1, 1983 to allow the Company to recover increases in debt costs.

These changes in Westcoast's tariff have different effects on operating income, cash flow and net income. The change in the method of collecting income taxes and the transfer of the Grizzly Valley costs to a deferred account impact operating income and, hence, cash flow, but have little effect on net income. The reduction in the rate of return on equity and recovery of increased debt costs, however, affect operating income, cash flow and net income.

These changes in the Company's cost of service had the following effects in 1983:

	Change in Tax Collection Method	Reduction in Return on Equity	Grizzly Valley Deferral	Increased Debt Recovery
	$ millions			
Operating Income	(21.5)	(1.4)	(1.0)	5.0
Cash Flow	(10.6)	(0.7)	(1.0)	2.4
Net Income	(0.3)	(0.7)	—	2.4

NET INCOME: (in millions)
BEFORE EXTRAORDINARY ITEM
INCLUDING EXTRAORDINARY ITEM



EARNINGS PER COMMON SHARE:
BEFORE EXTRAORDINARY ITEM
INCLUDING EXTRAORDINARY ITEM
DIVIDENDS PAID PER COMMON SHARE

Pictured are the valves which control natural gas flow from Westcoast's mainline at Huntingdon to the Company's export customer, Northwest Pipeline Corporation.
The natural gas is delivered to industrial, commercial and residential customers in Washington, Oregon, Idaho, Nevada and California.

The other principal factor affecting the operating results in 1983 was the lower capital expenditure program which resulted in the Company's average rate base declining in 1983 to $739 million from $748 million for 1982.

Westcoast's Investment in Assets

(non-consolidated basis)	December 31, 1983
Utility Rate Base and Other	77%
Foothills Pipe Lines (Yukon) Ltd.	9%
Westcoast Petroleum Ltd.	13%
Other Subsidiaries	1%
	100%

Foothills Pipe Lines (Yukon) Ltd.

Net income for 1983 from the Company's investment in Foothills was $11.8 million, down from $18.1 million a year earlier. This decline was primarily the result of the Company's decision to cease recording, as of January 1, 1983, its share of the allowance for funds used during construction relating to Phase II of the Alaska Highway Natural Gas Pipeline Project, partially offset by increased Phase II recovery in 1983.

The Company's net investment in Foothills after the extraordinary item amounted to $122 million at December 31, 1983. Dividends amounting to $15 million were received by the Company during 1983 from Foothills.

Westcoast Petroleum Ltd.

Net income from the Company's investment in Westcoast Petroleum increased to $12.7 million from $10.0 million during 1982. This increase resulted from the Company's acquisition of the balance of the outstanding shares of Westcoast Petroleum during 1982 and from an increase of $1 million in the earnings of West Petroleum in 1983.

The Company's investment in Westcoast Petroleum at December 31, 1983, amounted to $172 million. No dividends were received during the year by the Company from this investment.

The brilliant new addition to the foyer of Vancouver's Orpheum Theatre was officially opened in September 1983. Named Westcoast Hall in recognition of the Company's financial support, the new foyer provides much needed space for one of Vancouver's oldest and most important centres for the performing arts.

National Energy Board

In the National Energy Board's decision of August 1983, the Company's rate of return on rate base was revised from 17.9% before income tax, which was equivalent to 11.51% after income tax, to 12.05% after income tax.

The revised rate of return reflects a change in the method of collecting income taxes from the normalized basis to the flow-through basis. The revised rate incorporates the Company's increased cost of debt but is also designed to reduce the return on common shareholders' equity to 14.75%.

The NEB announced that a public hearing will commence in Vancouver on November 20, 1984 on the method of toll regulation and a variety of other matters. The NEB said that it would consider the Company's present variable cost of service system of tolls and a possible fixed-toll system of regulation. In addition, the NEB will consider matters with respect to depreciation. The hearing will not be concerned with the setting of specific tolls or tariffs.

Capitalization

The Company's financial statements shown in this report on pages 11 through 23, reflect a full consolidation of the financial results of all subsidiary companies and also a consolidation of Westcoast's proportionate share of the Foothills group of companies. The following table displays Westcoast's capital structure including and excluding the proportionate share of Foothills' long term debt. It should be noted that none of the Foothills' indebtedness is guaranteed by the sponsor companies.

	Consolidation Excluding Foothills		Consolidation Including Foothills	
	1983	1982	**1983**	1982
Long term debt	**53%**	52%	**59%**	58%
Preferred shares	**3%**	4%	**3%**	3%
Common equity	**44%**	44%	**38%**	39%
	100%	100%	**100%**	100%

Gas Sales and Supply

Gas Sales

Total sales of natural gas during the year declined by four percent from the 1982 level to 6 783 million cubic metres. Sales to domestic customers decreased two percent to 4 358 million cubic metres and exports to the United States were down seven percent to 2 425 million cubic metres.

The decline in sales to Westcoast's export customer, Northwest Pipeline Corporation, was attributed to warmer than normal weather, competition from residual fuel oil, depressed economic activity in the Pacific Northwest, and the high price of Canadian natural gas as compared to average prices for gas produced in the United States.

Sales to B.C. Hydro and Power Authority and Inland Natural Gas Co. Ltd. decreased respectively by five percent to 2 392 million cubic metres and seven percent to 1 260 million cubic metres, largely because of depressed economic activity and unseasonably high temperatures. Sales to Pacific Northern Gas Ltd. increased by 27 percent to 616 million cubic metres due to the increased gas delivery to Ocelot Industries Ltd.'s methanol plant in Kitimat, B.C.

Domestic Gas Prices

In July 1983, the British Columbia Ministry of Energy, Mines and Petroleum Resources announced gas price increases at both the well-head and wholesale levels, effective August 1, 1983. Westcoast was directed to raise its wholesale prices to B.C. Hydro and Power Authority, Inland Natural Gas Co. Ltd., and Pacific Northern Gas Ltd. The price increases did not affect earnings because under the Company's cost of service tariff, all additional revenue accrued to the Province.

Producer well-head prices per 28.3 cubic metres were raised from $1.54 to $1.75 for "old gas" and from $1.90 to $1.92 for "new gas".

Gas Reserves

In the Company's supply areas, proven gas reserves as of January 1, 1984 were 264 billion cubic metres. Despite low levels of drilling activity during 1983, recently available data from wells drilled in previous years indicate that additions to reserves have occurred to partially offset the production volumes. The most active source of future gas supply is the Grassy area in Northeastern British Columbia where six recently completed wells suggest the existence of substantial potential reserves.

Drilling Activity in British Columbia

Drilling activity in British Columbia fell from 108 wells in 1982 to 73 wells in 1983, compared to almost 400 wells per year in the peak period 1978 to 1980. Of the 73 wells drilled, 26 were completed as oil wells and 15 completed as gas wells.

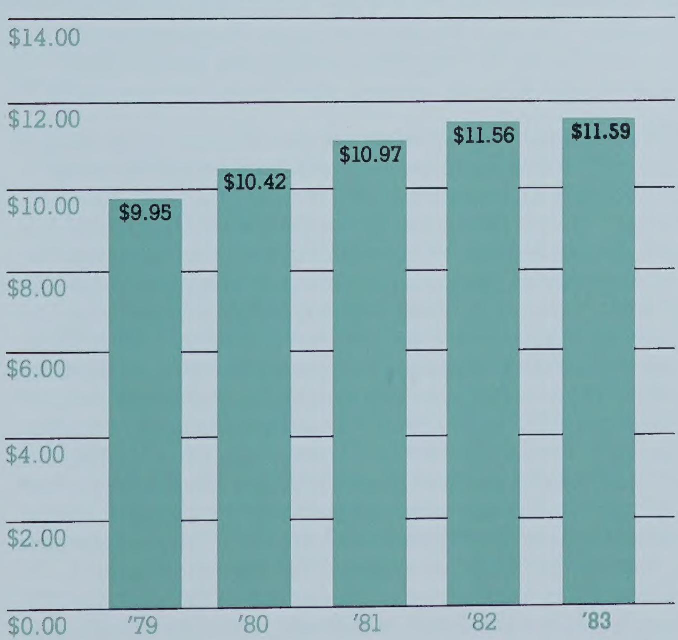
Construction and Operations

In 1983, Utility System construction activities amounted to $26 million. The Fort Nelson Sulphur Plant upgrade and expansion was completed increasing the sulphur plant capacity from 440 tonnes to 620 tonnes per day. Relatively minor upgrade and improvement projects were undertaken at the Fort Nelson Gas Plant and Taylor Sulphur Plant.

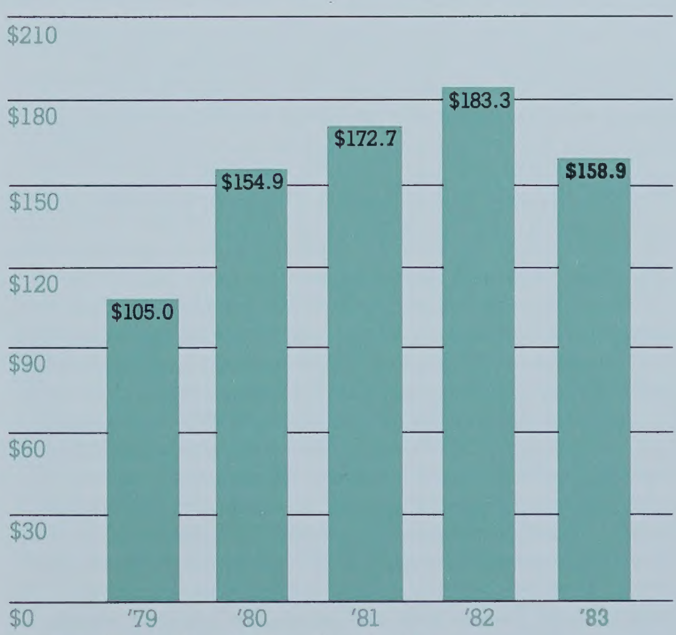
Capital expenditures for 1984 are anticipated to increase to $36 million and will include initial construction of a new computerized boiler plant control system for installation at the Fort Nelson Gas Plant and an inlet liquids handling project at the McMahon Gas Plant.

Although yearly total throughput was lower in 1983 than in 1982, the integrity of the pipeline system was tested on three peak days, being December 19, 22 and 23. The new peak day record was set on December 23 with sales reaching 43 million cubic metres.

SHAREHOLDERS' EQUITY PER COMMON SHARE



CASH FLOW FROM OPERATIONS* (in millions)



*Restated to reflect 1982 reclassification

Projects

Alaska Highway Natural Gas Pipeline Project

Delivery of western Canadian natural gas to the mid-western and west coast United States markets, through Phase I pipeline facilities of the Alaska Highway Natural Gas Pipeline Project, continued at approximately 40 percent of annual contract levels during 1983, reflecting the decline in export sales to the United States experienced by all Canadian marketers. Gas sales contract amendments have been made with the U.S. shippers to enable the shipment of lower annual volumes to the United States for a two-year period, while maintaining the existing regulatory-approved tariff which enables Foothills to recover the full cost of service for the pipeline facilities.

Vancouver Island Pipeline Project

At the invitation of the Province of British Columbia, the Company and Pacific Northern Gas Ltd. submitted applications to the British Columbia Utilities Commission for the construction of a pipeline to, and distribution facilities on, Vancouver Island.

This project, for which there are competing proposals, could be operational by late 1985 assuming regulatory approval is received by mid-1984.

The Company's proposal is to construct a pipeline from its main transmission line at Williams Lake to Powell River with twin pipe crossings under the Strait of Georgia to Comox on Vancouver Island and then a single line south from Comox to Victoria. The estimated capital cost to Westcoast for gas transmission facilities to and on Vancouver Island is $448 million, excluding the distribution system costs of Pacific Northern Gas Ltd.

Public hearings before the B.C. Utilities Commission commenced October 15, 1983 and are anticipated to conclude in April or May 1984.

Natural Gas Liquids Recovery Project

On February 14, 1984, the British Columbia Government announced support for a joint project by Westcoast and Petro-Canada to construct a natural gas liquids recovery project in British Columbia. The project, to cost approximately $65 million, includes a liquid extraction plant to be constructed at Taylor in northeast British Columbia and a fractionation plant to be constructed at Kamloops.

The Taylor plant will process 13 million cubic metres of natural gas per day to recover 4,800 barrels of natural gas liquids which will be transported to Kamloops in an existing crude oil pipeline owned by Westcoast Petroleum Ltd. Product distribution and marketing will be handled by Petro-Canada.

Construction is anticipated to begin in late 1984 with completion in the last quarter of 1985.

Liquefied Natural Gas Project

In May 1983, at the request of the sponsors of the Western LNG Project, Westcoast filed an application with the National Energy Board seeking authorization to construct gas transmission facilities within the Province of British Columbia to serve the liquefied natural gas project. The proposed pipeline facilities are estimated to cost $1 billion. Westcoast's application, and a companion application for the gas liquefaction plant, are being held in abeyance pending agreement with the Provinces of Alberta and British Columbia on gas feedstock prices and the conclusion of financial arrangements for the project. The current estimated completion date is 1987.

Fertilizer Complex

The Company continues to work with its consortium partners on the proposal for the construction of a nitrogen-fertilizer complex at Powell River, which is awaiting the outcome of the Vancouver Island pipeline hearing. The British Columbia Government announced that a portion of the Province's natural gas surplus has been allocated to the development of a fertilizer complex in the Province. With the Government's decision to restructure the natural gas industry in British Columbia, the potential for buying surplus gas at competitive rates has increased.

Coal-Methanol Slurry

During the past year further work was completed on this project which proposes to combine Alberta coal with methanol produced from Alberta gas to form a coal-methanol slurry, which would be pipelined across British Columbia and shipped to Japan and other offshore countries. Work over the past year has focused on determining the optimum mixture for burning coal, methanol and water. Results have been encouraging and the Company continues to pursue this project with its partners, Chieftain Development Co. Ltd. and the Government of Alberta.

Westcoast Petroleum Ltd.

Westcoast Petroleum Ltd., a wholly-owned subsidiary, is engaged in the exploration for, and production of, crude oil and natural gas, primarily in western Canada. It also operates a crude oil pipeline system in British Columbia which transports crude oil and natural gas liquids from Taylor to Prince George and Kamloops.

Westcoast Petroleum's net income, cash flow and oil production during 1983 reached new highs. Net income increased nine percent to $12,752,000 from the $11,735,000 earned in 1982 while cash generated from operations amounted to $30,410,000 compared with $29,107,000 in 1982, an increase of four percent. Revenues from the sale of crude oil and liquids were up 22 percent, although this gain was mostly offset by lower receipts from sales of natural gas.

Capital expenditures during 1983 were $49 million reflecting the continued high level of activity in Alberta and the first full year of exploration in the Beaufort Sea and Mackenzie Delta. Approximately $17 million of this capital program was financed by federal and Alberta government incentive payments.

Government Initiatives

In 1983 the federal government took action to ease the impact on industry of falling world oil prices. A cut of "old oil" prices triggered by declining world prices was waived, while the price for "middle-aged" oil was moved up to world price on August 1. As a result, 80 percent of the Westcoast Petroleum's oil production now receives the world price. Late in the year, Alberta relaxed its oil production regulations to allow wells with restricted output for conservation reasons, to increase production from 30 to 50 barrels per day. This concession will enhance the profitability of low reserve pools such as Suffield, where Westcoast Petroleum has a significant interest. In an effort to arrest further deterioration of domestic and export gas sales, the federal government cut export prices, offered volume discounts for export sales, reduced the excise tax on domestic sales, and, with the agreement of the Alberta government restrained producer price

Westcoast Petroleum is participating in a joint venture in the drilling of the Kadluk 0-07 well located 15 miles off shore in the Beaufort Sea. This is the first offshore well to be drilled from an island formed by a specially designed reuseable steel caisson.

increases which had been scheduled for domestic sales.

Exploration and Development

Westcoast Petroleum had an interest in 132 wells drilled during 1983 which compares with 115 wells drilled in 1982. Although no major discoveries resulted, reserves added through exploration and development were more than enough to replace oil and gas produced through the year.

Under the Esso Beaufort farm-in agreement, which earns Westcoast Petroleum a three percent interest in certain Esso lands, one offshore well and two onshore wells were drilled. Expendable well Esso PEX Home et al Itiyok 1-27, located on a sacrificial island, was drilled to a depth of 12,976 feet. Several potentially commercial zones were extensively tested prior to abandonment. Oil zones tested flowed medium gravity oil at rates of up to 2,500 barrels per day while gas bearing formations tested at rates up to 22 million cubic feet per day. It is not known whether this discovery is large enough to justify a commercial development, but it could be produced if later exploration should prove up additional reserves in the area. The two onshore wells did not encounter hydrocarbons.

In Alberta, Westcoast Petroleum participated in 90 wells. Drilling successes included five gas discoveries at Clear Hills in northern Alberta; five oil wells and one gas well at Gold Creek south of Grand Prairie; a Devonian gas discovery at Bezanson north of Grand Prairie; seven in-fill oil wells at Suffield in southeastern Alberta; and nine oil wells in the Crystal Viking oil field in central Alberta. At year end, Westcoast Petroleum had an interest in 36 wells in the Crystal field with Westcoast Petroleum's share of production averaging 1,150 barrels per day.

Westcoast Petroleum's program in the United States involved participation in 39 wells, with most of these drilled in western Nebraska. Seven wells were completed as oil wells. Follow-up drilling will depend on how these wells perform with time. In view of limited success, a decision has been made to reduce the 1984 exploration program in the United States.

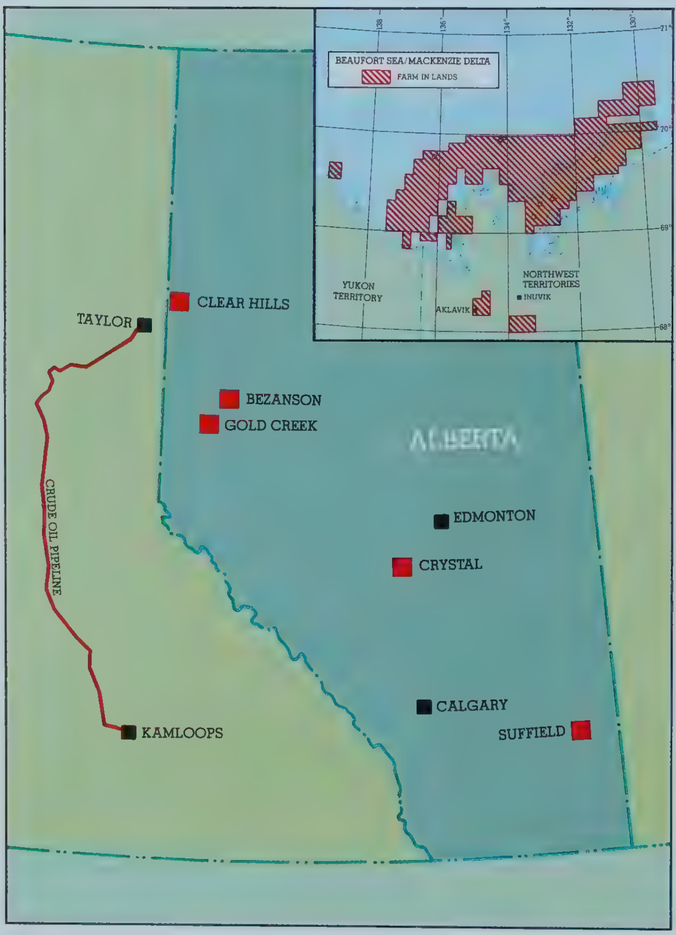
Production Operations

Natural gas sales continued to decline during 1983 due to the market situation. The major purchasers of Canadian gas took only 45 to 55 percent of contracted quantities, and consequently production during the year averaged only 24.8 million cubic feet per day compared with 32.1 million cubic feet for 1982.

Sales of crude oil and natural gas liquids averaged 3,234 barrels per day during the year compared with 3,046 barrels in 1982 — an increase of six percent. Development drilling in the Crystal and Suffield areas of Alberta added 375 barrels per day but these additions were partially offset by decline of some older pools.

Westcoast Petroleum, along with other working interest owners of the Crystal oil field, have agreed to unitize their interests and install a waterflood project covering the main producing area of the field. Engineering of the project and installation of facilities are underway and injection of water to enhance recovery of oil from the field is expected to begin during the last quarter of 1984. This $23 million project, managed by Westcoast Petroleum, is expected to improve recovery of oil three-fold, increasing Westcoast Petroleum's share of recoverable oil reserves by 8 million barrels and production by more than 1,000 barrels per day.

Principal Areas of Activity



Crude Oil Pipeline

Throughput of Westcoast Petroleum's pipeline averaged 28,354 barrels per day during the year compared with 26,699 in 1982. This operation contributed $1 million to Westcoast Petroleum's earnings for the year.

Summary of Land Holdings (Acres)

	December 31, 1983		December 31, 1982	
	Gross	**Net**	Gross	Net
Canada				
Alberta	**1,481,699**	**767,902**	1,522,205	848,804
British Columbia	**690,486**	**228,235**	755,877	249,042
Saskatchewan	**1,225**	**1,225**	1,225	1,225
Northwest Territories	**68,209**	**11,528**	68,209	11,528
Arctic Islands	**2,101,232**	— *	2,744,116	9,142
	4,342,851	**1,008,890**	5,091,632	1,119,741
United States	**195,391**	**71,077**	233,923	78,246
	4,538,242	**1,079,967**	5,325,555	1,197,987

*Royalty interest

Pacific Northern Gas Ltd.

Westcoast owns 45 percent of the common shares, including all the voting shares, of Pacific Northern Gas Ltd. This utility distributes natural gas in west-central British Columbia to communities and industries along its 589-kilometre system from a point near Summit Lake to Kitimat and Prince Rupert.

Pacific Northern reported net income after preferred dividends in 1983 of $3,701,000 or $2.31 per common share, compared with $2,900,000 or $1.81 per common share in 1982. Total sales revenue increased to $76,800,000 from $59,783,000 and sales volumes increased to 603 million cubic metres from 456 million cubic metres in 1982. The increases in volumes and revenue were mainly attributable to a full year's operation of the Ocelot Industries Ltd. methanol plant in Kitimat and a partial business recovery of forest-related industries.

Pacific Northern has an application before the British Columbia Utilities Commission to construct the "on-island" laterals and distribution system for natural gas to Vancouver Island residential, commercial and industrial users. This application awaits the conclusion of the "to" and "on-island" transmission portions of the Vancouver Island Pipeline hearings currently before the Utilities Commission.

Saratoga Processing Company Limited

Saratoga Processing Company Limited owns and operates both a natural gas pipeline and processing system and a sulphur extraction plant near Coleman, Alberta. The system has a daily capacity of approximately 1.4 million cubic metres of raw natural gas and processes gas on a fee basis for producers in the area.

Westcoast owns 25 percent of Saratoga's common shares, including all the voting shares.

Saratoga reported net income in 1983 of $860,000 or $1.72 per share, a decrease from $1,298,000 or $2.60 per share in 1982. A lower return on investment under Saratoga's agreements with the Savanna Creek and North Coleman producers and a decline in interest earned on short-term investments contributed to the reduction in net income. A further 56 cents per share of the reduction in the 1983 earnings, compared with 1982, is accounted for by the 1982 extraordinary gain of $280,000 from the sale of Saratoga's gathering system.

Financial Statements

Pictured at left are two service vehicles of the British Columbia Automobile Association being filled with compressed natural gas (CNG). The market for CNG, presently in its infancy, has enormous potential. Major commercial fleets such as those of the BCAA and Black Top Cabs Ltd. are now operating with CNG, and symbolize the cost-effective use of this important new fuel.

WESTCOAST TRANSMISSION COMPANY LIMITED
CONSOLIDATED BALANCE SHEETS

DECEMBER 31

	1983	1982
		(restated)
	(in thousands)	
Assets		
Plant, property and equipment (Note 2)	**$1,901,673**	$1,833,355
Less accumulated depreciation and depletion	**538,022**	469,467
	1,363,651	1,363,888
Current assets:		
Cash and temporary cash investments	**7,743**	5,414
Sinking fund deposits with trustees:		
Principal	**1,856**	1,571
Interest	**1,591**	1,359
Accounts receivable:		
Trade	**186,703**	161,559
Other	**15,250**	11,732
Materials and supplies	**13,807**	13,803
Line pack gas	**9,237**	8,805
Prepayments	**2,767**	2,582
Deferred operating expenses (Note 3)	**2,051**	1,923
	241,005	208,748
Deferred charges:		
Debt discount, premium and expense	**9,078**	8,999
Northern pipeline projects (Note 4)	**76,522**	101,242
Other (Note 5)	**28,796**	25,036
	114,396	135,277
	$1,719,052	$1,707,913

Auditors' Report

To the Shareholders of
Westcoast Transmission Company Limited:

We have examined the consolidated balance sheets and the consolidated statements of long term debt of Westcoast Transmission Company Limited as at December 31, 1983 and 1982 and the consolidated statements of operations, retained earnings and changes in financial position for the three years ended December 31, 1983. Our examinations were made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the company as at December 31, 1983 and 1982 and the results of its operations and the changes in its financial position for the three years ended December 31, 1983 in accordance with accounting principles generally accepted in Canada, consistently applied, except for the change in 1983, with which we concur, in the basis of accounting for income taxes as explained in Note 1 to the consolidated financial statements.

Vancouver, Canada,
February 3, 1984

CLARKSON GORDON
Chartered Accountants

WESTCOAST TRANSMISSION COMPANY LIMITED
CONSOLIDATED BALANCE SHEETS

DECEMBER 31

	1983	1982 (restated)
	(in thousands)	
Common Shareholders' Equity		
Common stock (Note 6):		
Authorized — 75,000,000 common shares without nominal or par value		
Issued — 40,731,498 common shares (1982 — 40,689,998 common shares)	**$ 233,517**	$ 233,219
Contributed surplus	**2,123**	2,155
Retained earnings	**236,556**	234,808
	472,196	470,182
Preferred Shareholders' Equity		
Preferred stock (Note 9):		
Authorized — 5,000,000 preferred shares without nominal or par value		
Issued — 739,322 $4.25 cumulative redeemable preferred shares series A	**36,966**	36,966
Liabilities		
Long term obligations:		
Long term debt (Note 12)	**732,421**	701,618
Deferred income taxes (Note 13)	**215,445**	202,270
	947,866	903,888
Current liabilities:		
Bank indebtedness	**—**	78,467
Accounts payable	**166,084**	136,363
Income and other taxes payable (Note 13)	**26,552**	17,194
Interest on debt	**19,507**	18,997
Long term debt due within one year	**27,929**	25,486
	240,072	276,507
Minority interest in subsidiary companies:		
Preferred shares	**5,000**	5,000
Common shares	**16,952**	15,370
	21,952	20,370
Commitments and contingencies (Note 16)		
	$1,719,052	$1,707,913

(See accompanying notes)

On behalf of the Board:

Director [signature] Director John Anderson

WESTCOAST TRANSMISSION COMPANY LIMITED
CONSOLIDATED STATEMENTS OF OPERATIONS

FOR THE YEARS ENDED DECEMBER 31

	1983	1982	1981
		(restated) (in thousands)	
Operating revenues:			
Gas and oil sales	**$1,064,204**	$1,113,841	$1,252,530
Other	**62,901**	43,110	17,800
	1,127,105	1,156,951	1,270,330
Operating revenue deductions:			
Cost of gas sold	**701,819**	737,389	867,712
Operation and maintenance (Note 3)	**109,108**	103,324	106,384
Depreciation and depletion	**70,645**	66,279	57,507
Taxes — other than income taxes	**52,693**	53,865	72,940
	934,265	960,857	1,104,543
Operating income	**192,840**	196,094	165,787
Other income:			
Allowance for funds used during construction	**2,309**	30,768	31,591
Northern pipeline projects Phase II recovery (Note 4)	**3,486**	1,192	—
Investment and other income (Note 5)	**3,120**	4,344	5,987
	201,755	232,398	203,365
Income deductions:			
Interest on debt (Note 12)	**91,293**	91,655	68,952
Debt discount, premium and expense	**1,056**	762	722
Other	**438**	2,581	(503)
	92,787	94,998	69,171
Income before undernoted items	**108,968**	137,400	134,194
Income taxes (Note 13):			
Current	**21,050**	6,814	5,899
Deferred	**19,366**	55,722	57,555
	40,416	62,536	63,454
Minority interest	**3,463**	4,817	5,314
Income before extraordinary item	**65,089**	70,047	65,426
Extraordinary item, net of deferred income taxes (Note 4)	**16,645**	—	—
Net income	**48,444**	70,047	65,426
Provision for dividends on preferred shares	**3,142**	3,142	3,142
Net income applicable to common shares:			
Including extraordinary item	**$ 45,302**	$ 66,905	$ 62,284
Before extraordinary item	**$ 61,947**	$ 66,905	$ 62,284
Common shares outstanding — weighted average	**40,721**	40,632	39,247
Per common share — basic (Note 7):			
Including extraordinary item	**$1.11**	$1.65	$1.59
Before extraordinary item	**$1.52**	$1.65	$1.59
Dividends per common share	**$1.04**	$1.04	$ .92

(See accompanying notes)

WESTCOAST TRANSMISSION COMPANY LIMITED
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

FOR THE YEARS ENDED DECEMBER 31

	1983	1982	1981
		(in thousands)	
Unappropriated retained earnings:			
Balance, beginning of year	**$197,842**	$174,491	$148,785
Net income	**48,444**	70,047	65,426
Tax allocation (Note 1)	**(1,202)**	(1,274)	—
	245,084	243,264	214,211
Deduct dividends paid:			
Common shares	**42,352**	42,280	36,578
Preferred shares	**3,142**	3,142	3,142
	45,494	45,422	39,720
Balance, end of year	**199,590**	197,842	174,491
Appropriated retained earnings (Note 10):			
Reserve for redemption of preferred shares	**36,966**	36,966	36,966
Retained earnings, end of year	**$236,556**	$234,808	$211,457

(See accompanying notes)

WESTCOAST TRANSMISSION COMPANY LIMITED
CONSOLIDATED STATEMENTS OF CHANGES IN FINANCIAL POSITION

FOR THE YEARS ENDED DECEMBER 31

	1983	1982 (restated)	1981
		(in thousands)	
Funds derived from:			
Operations:			
Income before extraordinary item	**$ 65,089**	$ 70,047	$ 65,426
Add (deduct) items not involving a flow of funds:			
Minority interest	**3,463**	4,817	5,314
Deferred income taxes	**19,366**	55,722	57,555
Depreciation, depletion and amortization	**70,726**	66,416	57,481
Debt discount, premium and expense	**1,056**	762	722
Allowance for equity funds used during construction	**(825)**	(14,496)	(13,799)
	158,875	183,268	172,699
Petroleum incentives	**17,201**	13,065	4,140
Common shares issued	**298**	631	42,872
Additional long term debt	**71,328**	131,981	98,769
	$247,702	$328,945	$318,480
Funds used for:			
Additions to plant, property and equipment:			
Westcoast utility system	**$ 26,303**	$ 76,397	$ 62,871
Westcoast Petroleum property acquisition, exploration and development costs	**48,552**	50,043	31,991
Other	**14,988**	79,884	142,425
Long term debt retirement	**41,692**	27,619	28,711
Dividends	**45,494**	45,422	39,720
Dividends paid by subsidiaries to minority interests	**1,593**	2,255	1,097
Investment in Westcoast Petroleum (Note 15)	**—**	87,667	2,115
Northern pipeline projects	**(1,171)**	13,094	1,752
Other	**1,559**	12,885	8,666
Working capital increase (decrease)	**68,692**	(66,321)	(868)
	$247,702	$328,945	$318,480
Changes in working capital components:			
Cash and temporary cash investments	**$ 2,329**	$ 6,229	$ (9,730)
Deposits with trustees	**517**	(269)	(284)
Accounts receivable	**28,662**	15,443	(9,164)
Materials and supplies	**4**	3,306	2,457
Line pack gas	**432**	804	(963)
Prepayments	**185**	965	523
Deferred operating expenses	**128**	(926)	(7,567)
Bank indebtedness	**78,467**	(65,597)	673
Accounts payable	**(29,721)**	(7,736)	30,809
Income and other taxes payable	**(9,358)**	(8,685)	(3,755)
Interest on debt	**(510)**	(3,691)	(125)
Long term debt due within one year	**(2,443)**	(6,164)	(3,742)
Working capital increase (decrease)	**$ 68,692**	$ (66,321)	$ (868)

(See accompanying notes)

WESTCOAST TRANSMISSION COMPANY LIMITED
CONSOLIDATED STATEMENTS OF LONG TERM DEBT

DECEMBER 31

		1983		1982	
	Due Date	**United States Dollars**	**Canadian Dollars**	United States Dollars	Canadian Dollars
			(in thousands)		
Westcoast Transmission Company Limited					
First Mortgage Pipe Line Bonds					
5¾% Series D	1984	**$**	**$ 3,119**	$	$ 6,117
5¾% Series E	1984		**1,305**		2,367
7% Series F	1988	**18,544**	**20,664**	22,626	25,000
8% Series G	1991		**58,341**		62,011
9¾% Series H	1996	**41,000**	**40,953**	43,250	43,134
Debentures					
7½% Debentures, First Series	1991		**502**		615
8½% Debentures, 1993 Series	1993		**35,473**		37,591
9⅞% Debentures, 1998 Series	1998		**72,479**		75,000
10½% Debentures, 1999 Series	1999		**75,000**		75,000
12¼% Debentures, 2000 Series	2000		**100,000**		100,000
16¾% Debentures, 1987 Series	1987		**50,000**		50,000
12½% Debentures, 1993 Series	1993		**60,000**		—
Subordinate Debentures					
5½% Series A	1988	**7,420**	**7,702**	8,142	8,212
5½% Series B	1988	**831**	**796**	832	797
5½% Series C	1988	**1,138**	**1,150**	1,375	1,377
Vancal Properties Ltd.					
7½% Secured Notes	1994	**3,308**	**3,550**	3,496	3,750
Westcoast Petroleum Ltd.					
Term Bank Loan	1984		**2,367**		2,467
Sinking Fund Debentures 10%, First Series	1993		**16,250**		17,500
Pacific Northern Gas Ltd.					
Construction Advances			**994**		622
First Mortgage Pipe Line Bonds					
7¾% Series A	1988	**5,087**	**5,470**	6,012	6,463
9¼% Series B (Note 12)	1991	**1,480**	**1,492**	1,665	1,679
Debentures					
17¾% Debentures, 1987 Series	1987		**12,500**		12,500
18% Debentures, 1997 Series	1997		**27,500**		27,500
Foothills Pipe Lines (Yukon) Ltd.					
Bank Loan			**1,169**		13,478
Term Bank Loans	1988/96		**161,574**		153,924
			760,350		727,104
Deduct long term debt due within one year			**27,929**		25,486
			$732,421		$701,618

(See accompanying notes)

WESTCOAST TRANSMISSION COMPANY LIMITED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 1983

1. Accounting Policies:

Accounting Principles:

The Company prepares its accounts in accordance with generally accepted accounting principles followed in Canada which, except as described in Note 14, conform in all material respects with generally accepted accounting principles followed in the United States.

Principles of Consolidation:

The consolidated financial statements include the accounts of the Company and the following:

- Westcoast Transmission Company (Alberta) Ltd. (100% owned)
- Westcoast Transmission Holdings Ltd. (100% owned)
- Vancal Properties Ltd. (100% owned)
- Saratoga Processing Company Limited (25% owned, including 100% of the voting shares)
- Pacific Northern Gas Ltd. (45% owned, including 100% of the voting shares)
- Westcoast Petroleum Ltd. (December 31, 1983 and 1982 — 100% directly and indirectly owned, December 31, 1981 — 58.3% owned including 57.3% of the voting shares) (Note 15)
- Foothills Pipe Lines (Yukon) Ltd. (50% owned, proportionately consolidated)
- Foothills Pipe Lines (North B.C.) Ltd. (74.5% directly and indirectly owned, proportionately consolidated)

Regulation:

The Company is subject to the National Energy Board Act and to the jurisdiction of the National Energy Board. That Board regulates accounting matters, exports of natural gas, construction and operation of natural gas pipelines and the rates, tolls and charges of the Company.

Cost of Service:

The Company and its subsidiary, Westcoast Transmission Company (Alberta) Ltd., operate under a gas purchase agreement with the British Columbia Petroleum Corporation, a Crown corporation of the Province of British Columbia. Under this agreement, the Company is reimbursed for costs which include operating, maintenance and administrative expenses, depreciation of the Company's investment in utility assets, income taxes and other taxes. The agreement also enables the Company to receive a return on its utility rate base (primarily the undepreciated portion of plant, property and equipment) and also provides for the reimbursement of that portion of foreign exchange gains or losses on foreign debt repayments and foreign interest payments associated with the financing of its utility rate base and construction work in progress.

Operating, Maintenance and Administrative Expenses:

The Company's reimbursement of its operating, maintenance and administrative expenses pertaining to its utility system is limited to amounts approved from time to time by the National Energy Board. If expenses exceed the approved amounts, the recovery of the excess together with related carrying costs are deferred pending the Board's decision to permit recovery by way of inclusion in the Company's cost of service in the subsequent year. Any amounts not allowed to be included in cost of service result in a reduction of the Company's net income.

Rate of Return on Rate Base:

The National Energy Board directed the Company to adopt, effective January 1, 1983, a rate of return on capital employed in rate base of 12.05% on an after income tax basis and to recover income taxes currently payable through cost of service.

For the year ended December 31, 1982 and the five months ended December 31, 1981 the Company's approved rate of return before income taxes on rate base was 17.90% which, after taking into account income taxes calculated on the income tax allocation basis was based on an after income tax rate of 11.51%. For the seven months ended July 31, 1981, the Company's approved rate of return before income taxes on rate base was 17.65% which, taking into account a lower effective income tax rate which prevailed in 1981, was also based on an after income tax rate of 11.51%.

Income Taxes:

The National Energy Board directed the Company to adopt, effective January 1, 1983, the income taxes currently payable basis of accounting for income tax liabilities for its utility operations and to recover these income taxes through cost of service. Under this basis, no provision is made for income taxes deferred as a result of differences in timing between the treatment for income tax and book purposes of various items of income and expenditure. The Company continues to use the income tax allocation basis for its non-regulated operations.

For the period November 1, 1979 to December 31, 1982 the Company was directed to use the income tax allocation basis of accounting for income tax liabilities under which provision is made for income taxes deferred as a result of differences in timing between the treatment for income tax and book purposes of various items of income and expenditure. Prior to November 1, 1979, the income taxes currently payable basis was used. Items deducted for income tax purposes that were related to the Company's non-regulated operations prior to November 1, 1979 and which involved timing differences between the income tax and accounting treatment, necessitate a charge to retained earnings upon the reversal of these timing differences.

Investment tax credits are accounted for using the deferral basis for non-regulated operations and the currently payable basis for utility operations.

Westcoast Petroleum Ltd., Pacific Northern Gas Ltd., and Foothills Pipe Lines (Yukon) Ltd. provide for income taxes on the tax allocation basis.

Effective January 1, 1982 Saratoga Processing Company Limited adopted the income tax allocation basis of accounting for income taxes. Saratoga Processing Company Limited previously used the income taxes currently payable basis.

Westcoast Transmission Company (Alberta) Ltd. provides for income taxes on the income taxes currently payable basis.

If all the companies had used the tax allocation basis to provide for income taxes the provision for the year would have increased by $3,084,000 (decreased for the years ended December 31, 1982 — $1,113,000, December 31, 1981 — $412,500) and the unrecorded accumulated provision to December 31, 1983 would have been $164,360,000 (December 31, 1982 — $161,276,000, December 31, 1981 — $162,389,000).

Translation of United States Funds:

The Company's United States funds on deposit with banks and trustees and current liabilities payable in United States funds have been translated to Canadian dollars at the exchange rates prevailing at the end of the fiscal periods and, with the exception of the portion of long term debt due within one year, the resulting gains or losses have been reflected in income. The gain or loss attributed to the portion of long term debt due within one year is deferred because the major portion is recoverable through the Company's cost of service. Long term debt, exclusive of the portion of long term debt due within one year, and capital stock issued in United States funds have been translated at exchange rates prevailing at the respective dates of issue. Exchange gains or losses resulting from redemptions or purchases of long term debt, net of the portion recovered through cost of service, are included in income.

Plant, Property and Equipment:

Plant, property and equipment are valued at cost. The Company follows the full-cost method of accounting wherein all costs related to the acquisition, exploration and development of oil and gas reserves are capitalized. Federal and Provincial incentive payments for exploration and development are treated as a deduction in the cost of related assets.

Capitalization and Maintenance:

Maintenance and repairs are charged to expense accounts when incurred. The cost of major replacements, extensions or improvements is capitalized as plant, property and equipment. Upon retirement or sale of items of plant, property or equipment, the original cost of such items is charged against the applicable accumulated depreciation account and the net proceeds of disposal are credited to accumulated depreciation.

Allowance for Funds Used During Construction:

The National Energy Board directed the Company to adopt, effective January 1, 1983, the prescribed after income tax rate of return on rate base of 12.05% for calculating an allowance for funds used during construction to be charged to plant, property and equipment (for the years ended December 31, 1982 and 1981 — 11.51%).

The consolidated financial statements also reflect an allowance for funds used during construction recorded with respect to construction in progress of Pacific Northern Gas Ltd., Saratoga Processing Company Limited and Phases I and II of the Northern Pipeline Projects. The respective allowance rates are the demand loan rates for Pacific Northern Gas Ltd., 14.25% for Saratoga Processing Company Limited and 17.50% for Phase I of the Northern Pipeline Projects. The allowance rates for Phase II of the Northern Pipeline Projects are described in Note 4.

Depreciation and Depletion:

Depreciation is calculated using straight-line rates determined on the economic or physical life of the assets in service as appropriate. The various rates used by the Company resulted in a composite rate of 4.6% for the year ended December 31, 1983 (for the years ended December 31, 1982 — 4.2%, December 31, 1981 — 4.5%).

Depletion of oil and gas properties is calculated by a composite unit-of-production method based on total estimated proven reserves.

Temporary Cash Investments:

Temporary cash investments are valued at cost which approximates market value.

Materials and Supplies:

Materials and supplies are valued at the lower of the weighted average cost determined on a first-in, first-out basis or net realizable value.

Line Pack Gas:

Line pack gas is valued at cost.

Deferred Charges:

Debt discount, premium and expense is being amortized over the life of the respective debt issues.

Costs relating to the Northern Pipeline Projects and other projects which may benefit future periods are being deferred. Deferred costs applicable to projects which have been terminated are expensed.

Contributed Surplus:

The contributed surplus shown in the Company's accounts is primarily related to contributions and grants received in aid of construction which were deducted from the Company's rate base. In order to conform the rate base to amounts of fixed assets as recorded, the Company is, with National Energy Board approval, restoring the amounts of the contributions to rate base over a 60-month period and reducing cost of service by the same amount.

Pension Plan:

The Company has a non-contributory pension plan covering substantially all employees. The Company charged to operations $969,000 during the year ended December 31, 1983 (for the years ended December 31, 1982 — $1,576,000, December 31, 1981 — $1,505,000). The plan is subject to periodic actuarial evaluations, with the last one made as at December 31, 1979. At that time there was no unfunded liability. The next actuarial evaluation, as at December 31, 1983, will be completed in 1984.

Comparative Figures:

The comparative figures have been reclassified to conform to the 1983 presentation.

2. Plant, Property and Equipment:

	December 31 1983	1982 (restated)
	$000	
Westcoast Transmission Company Limited and its Utility Subsidiary		
Gathering plant	**$ 283,025**	$ 297,048
Products extraction plant	**285,492**	275,809
Transmission plant	**548,247**	538,556
Miscellaneous plant and equipment	**58,228**	40,824*
Construction work in progress	**7,853**	8,791
	1,182,845	1,161,028
Westcoast Petroleum Ltd.		
Transmission plant	**41,041**	41,041
Oil and gas properties	**327,168**	294,818
	368,209	335,859
Other Subsidiaries		
Gathering plant	**3,434**	3,434
Products extraction plant	**7,205**	6,526
Transmission plant	**79,339**	77,133
Distribution plant	**18,752**	17,391
Miscellaneous plant and equipment	**8,971**	8,158
Construction work in progress	**1,785**	762
	119,486	113,404
Foothills Pipe Lines (Yukon) Ltd.		
Transmission plant and equipment	**231,108**	199,144
Construction work in progress	**25**	23,920
	231,133	223,064
Total plant, property and equipment	**1,901,673**	1,833,355
Deduct:		
Accumulated depreciation		
Westcoast Transmission and its Utility Subsidiary	**397,744**	350,198
Westcoast Petroleum Ltd.	**47,426**	44,776
Other Subsidiaries	**24,334**	21,846
Foothills Pipe Lines (Yukon) Ltd.	**15,465**	8,817
	484,969	425,637
Accumulated depletion Westcoast Petroleum Ltd.	**53,053**	43,830
Total accumulated depreciation and depletion	**538,022**	469,467
	$1,363,651	$1,363,888

*Restated to reflect reversal of investment tax credit (Note 13)

3. Deferred Operating Expenses:

For the year ended December 31, 1983, the Company's actual operating and maintenance expenses fell below the amount budgeted and approved by the National Energy Board. However, certain cost centres had actual expenditures in excess of the approved amounts by an aggregate of $2,031,000. The Company has not charged this aggregate amount and the carrying charges accrued thereon to cost of service for the year ended December 31, 1983. The Company has made an application for the recovery of these deferred expenses and the carrying charges accrued to the date of recovery. Any amount not allowed to be included in the cost of service will result in a reduction of the Company's net income.

Following receipt of approval from the National Energy Board, the Company recovered in its 1983 cost of service

$1,599,000 of the deferred expenses for the year ended December 31, 1982 and the related carrying charges totalling $239,000. Other deferred expenses of $211,000 were not approved for recovery through cost of service and were therefore transferred to operating expenses in 1983.

The Company received approvals from the National Energy Board and recovered in its 1982 cost of service the deferred expenses for the year ended December 31, 1981 of $2,781,000 and the related carrying charges totalling $374,000, and in its 1981 cost of service the deferred expenses for the six months ended December 31, 1980 of $3,508,000 and for the twelve months ended June 30, 1980 of $6,226,000 and the related carrying charges totalling $1,487,000.

4. Northern Pipeline Projects:

The Company owns 50% of the outstanding common shares of Foothills Pipe Lines (Yukon) Ltd. which has been given the responsibility by the National Energy Board for co-ordinating and directing the Canadian portion of the Alaska Highway Natural Gas Pipeline Project. The Canadian portion of the project has two principal objectives. The first is the transportation of Alaskan natural gas from the Alaska-Yukon border to Monchy, Saskatchewan and Kingsgate, British Columbia at the Canada-United States border. The second objective is the transportation of Canadian natural gas by way of a pipeline known as the Dempster Link from the Mackenzie Delta-Beaufort Basin area to the Canadian portion of the Alaska Highway Natural Gas Pipeline. An application to construct the Dempster Link was filed with the National Energy Board on June 29, 1979.

Phase I of the project consists of the southern segment of the Canadian portion with the construction of facilities for the Eastern Leg from Caroline, Alberta to Monchy, Saskatchewan and the Western Leg from Caroline to Kingsgate, British Columbia for the delivery of Canadian natural gas prior to the delivery of Alaskan natural gas. The balance of the Canadian portion of the project is known as Phase II. Foothills Pipe Lines (Yukon) Ltd. has completed construction of Phase I and Alberta gas commenced to flow in October 1981 through the Western Leg and in September 1982 through the Eastern Leg.

With respect to Phase II of the Northern Pipeline Project, the National Energy Board directed Foothills Pipe Lines (Yukon) Ltd. to record effective January 1, 1981 an allowance for funds used during construction at composite rates made up of the sponsor companies' approved rate of return on rate base plus a project risk premium. The Company recorded in income and added to its investment its pro rata share of the allowance for funds used during construction at composite rates varying between 11.51% and 13.30% for the period January 1, 1981 to August 31, 1982.

As of September 1, 1982, the National Energy Board directed Foothills Pipe Lines (Yukon) Ltd. to begin recovering approximately $124,000,000 (of which Westcoast's share is approximately $49,000,000) of Phase II expenditures under the tariff applicable to the Phase I operations. The National Energy Board also permitted Foothills Pipe Lines (Yukon) Ltd. a return of 16% before income tax on the undepreciated balance of $124,000,000.

Due to the extension of the projected completion date of Phase II to 1989 and because it is not possible at present to establish a date certain for the commencement of any construction activities, the Company, as of September 1, 1982, reduced its recognition of its pro rata share of the allowance for funds used during construction, and as of January 1, 1983 discontinued recording its pro rata share of the allowance for funds used during construction recorded by Foothills Pipe Lines (Yukon) Ltd. with respect to the balance of the Phase II expenditures. Furthermore, due to the continuing uncertainty of the timing of the project, a substantial change has occurred in the original program. Accordingly, an extraordinary provision covering certain costs relating to Phase II is reflected in the 1983 Consolidated Statements of Operations of $23,549,000 less income tax effect of $6,904,000.

The components of the Company's consolidated financial statements relating to its share of the activities of Foothills Pipe Lines (Yukon) Ltd. and its subsidiaries are shown below:

Balance Sheets

	December 31		
	1983	1982 (restated)	1981
		$000	
Plant, property and equipment	**$231,133**	$223,064	$144,794
Accumulated depreciation	**(15,465)**	(8,817)	(1,752)
Current assets	**10,918**	13,368	905
Northern pipeline projects	**76,522**	101,242	81,747
	$303,108	$328,857	$225,694
Long term debt	**$156,035**	$157,390	$ 87,593
Deferred income taxes	**12,421**	4,768	584
Current liabilities	**13,297**	17,138	19,114
Westcoast equity:			
Phase I*	**44,833**	48,319	36,656
Phase II*	**76,522**	101,242	81,747
	$303,108	$328,857	$225,694

*These amounts represent the Company's carrying value of its share in the projects prior to taking into account income tax savings realized in prior years amounting to $20,341,000 which are recorded in the Company's accounts.

Statements of Operations

	For the years ended December 31		
	1983	1982 (restated)	1981
		$000	
Operating revenues	**$ 49,157**	$ 27,457	$ 4,641
Operating revenue deductions	**14,006**	9,220	2,026
	35,151	18,237	2,615
Allowance for funds used during construction	**852**	25,747	27,257
Northern pipeline projects Phase II recovery	**3,486**	1,192	—
Other income	**1,001**	635	27
	40,490	45,811	29,899
Interest on debt	**20,662**	23,481	15,904
	19,828	22,330	13,995
Income taxes	**8,073**	4,184	584
Income before extraordinary item	**$ 11,755**	$ 18,146	$ 13,411

5. Other Deferred Charges:

Reflected in deferred charges as of December 31, 1983 is an amount of $24,155,000 which represents $23,093,000 of repair costs relating to the Grizzly Valley Pipeline together with carrying charges to December 31, 1983 amounting to $1,062,000. In its decision of August 1983 on the Company's 1983 rate application, the National Energy Board directed the Company, on an interim basis, to transfer from its rate base for cost of service purposes, to a deferral account, the $24,217,000 of costs incurred in the replacement of defective pipe in the Grizzly Valley Pipeline. The National Energy Board further directed the Company to accumulate deferred carrying charges at the Company's allowed rate of return on rate base of 12.05%. This interim provision is to continue in effect until either the conclusion of the litigation commenced by the Company or December 31, 1985, whichever is the earlier.

6. Common Stock:

(a) During 1983 the Company issued:
 (i) 41,500 common shares on options exercised at option prices ranging from $5.166 to $13.50 per share, increasing common stock by $298,000.

(b) During 1982 the Company issued:
 (i) 75,000 common shares on options exercised at option prices ranging from $6.458 to $12.00 per share, increasing common stock by $631,000.

(c) During 1981 the Company issued:
 (i) 4,058,217 common shares on Share Purchase Warrants exercised at a price of $9.44 per share, increasing common stock by $38,310,000. The warrants expired on May 15, 1981; and
 (ii) 367,200 common shares on options exercised at option prices ranging from $6.458 to $15.00 per share, increasing common stock by $4,562,000.

(d) Common share reservations and options:
 (i) Share options which became exercisable and options exercised are summarized below:

	December 31	
	1983	1982
Number of shares with respect to which options became exercisable	**83,700**	48,000
Option price:		
Per share — range	**$11.50 - $15.00**	$11.50 - $15.00
Total	**$1,209,000**	$645,000
Fair value:		
Per share — average	**$14.57**	$12.68
Total	**$1,220,000**	$609,000
Number of shares with respect to which options were exercised*	**41,500**	75,000
Option price:		
Per share — range	**$5.166 - $13.50**	$6.458 -$12.00
Total	**$298,000**	$631,000
Fair value:		
Per share — average	**$14.43**	$14.68
Total	**$599,000**	$1,101,000

*Upon the issuance of common shares under these options the proceeds are credited to the common stock account. No charges are made against income with respect to these transactions.

 (ii) Included in the common shares reserved for outstanding options, as set out below, are 268,000 common shares optioned to directors and officers (December 31, 1982 — 106,000 common shares):

Date Granted	Original Number of Shares Optioned	Option Price*	Shares Under Option
	December 31, 1983		
April 20, 1976	**150,000**	**$ 7.875**	**53,500**
April 19, 1979	**162,000**	**$13.50**	**69,600**
February 5, 1980	**131,000**	**$14.50**	**16,000**
February 10, 1981	**76,000**	**$15.00**	**66,000**
October 28, 1981	**177,200**	**$11.50**	**9,000**
February 9, 1983	**108,500**	**$14.25**	**108,500**
October 27, 1983	**145,000**	**$15.00**	**145,000**
	949,700		**467,600**
	December 31, 1982		
October 16, 1973	45,000	$ 5.166	15,000
July 29, 1974	45,000	$ 6.458	7,500
April 20, 1976	150,000	$ 7.875	68,500
April 19, 1979	162,000	$13.50	73,600
February 5, 1980	131,000	$14.50	16,000
February 10, 1981	76,000	$15.00	66,000
October 28, 1981	177,200	$11.50	9,000
	786,200		255,600

*Option price equals fair value at grant date.

 (iii) On April 27, 1983 the shareholders approved the reservation of 500,000 common shares for employee options of which 336,925 have not been allocated. The Directors may from time to time grant options at an option price of not less than 90% of the closing price of the common shares of the Company on the Toronto Stock Exchange on the day any such option is granted. The options are generally exercisable at the cumulative rate of 20% per year.

7. Earnings per Common Share:

Basic earnings per common share are calculated using the weighted average number of common shares outstanding during the fiscal period. In 1983, there would be no dilutive effect on earnings per common share as the result of the exercise of share purchase options.

	For the years ended December 31		
	1983	1982	1981
Number of shares (000)			
Beginning balance	**40,690**	40,615	36,190
Changes due to:			
Options exercised	**41**	75	367
Warrants exercised	**—**	—	4,058
Ending balance	**40,731**	40,690	40,615
Weighted average	**40,721**	40,632	39,247
Net income applicable to common shares: ($000)			
Before extraordinary item	**$61,947**	$66,905	$62,284
Including extraordinary item	**45,302**	66,905	62,284
Basic earnings per common share:			
Before extraordinary item	**$1.52**	$1.65	$1.59
Including extraordinary item	**1.11**	1.65	1.59

8. Segmented Information:

More than 90% of the consolidated revenue and net income of the Company are derived from the sale of natural gas produced in Canada. In excess of 90% of the consolidated assets of the Company are situated in Canada and are used for the processing, transporting and sale of natural gas produced in Canada. The consolidated operating revenues of the Company are generated from the following sources:

	For the years ended December 31		
	1983	1982	1981
		(restated) $000	
Canada	**$ 503,634**	$ 422,963	$ 285,133
United States — sales to Northwest Pipeline Corporation	**623,471**	733,988	985,197
Total	**$1,127,105**	$1,156,951	$1,270,330

9. Preferred Stock:

The Preferred Shares Series A are redeemable at the option of the Company at any time in whole or in part on not less than 30 days notice at varying redemption prices ranging from $51.25 if redeemed on or before December 31, 1984 and $50.50 if redeemed thereafter.

The Company, during the six month period ending December 31, 1984, is required under the terms of issue to invite tenders for redemption from the holders of the Preferred Shares Series A at a price equal to $50.00 plus accrued and unpaid preferential dividends. All tenders received by February 14, 1985 shall be accepted.

10. Appropriated Retained Earnings:

The Company has provided a Retraction Purchase Fund which will be returned to unappropriated retained earnings as the Preferred Shares Series A are redeemed.

11. Dividend Restriction:

The First Mortgage and the indentures relating to the Company's long term debt and preferred shares contain restrictions as to the declaration or payment of dividends (other than stock dividends) on common shares. Under the most restrictive provision, the amount available for dividends at December 31, 1983 is $124,000,000 (December 31, 1982 — $126,000,000, December 31, 1981 — $108,000,000).

12. Long Term Debt:

Long term debt payments, including sinking fund obligations, required in the five years ending December 31, 1988 are:
1984-$27,929,000 1985-$57,590,000 1986-$59,560,000
1987-$122,826,000 1988-$58,718,000

The 9¼% First Mortgage Pipe Line Bonds, Series B of Pacific Northern Gas Ltd. include detachable warrants to purchase 50,000 Class A common shares of Pacific Northern Gas Ltd. at $5.00 per share until maturity.

The translation of long term debt payable in United States funds at the exchange rate prevailing at the end of the fiscal year would increase long term debt including the portion due within one year (which is translated at the year-end rate of exchange) as of December 31, 1983 to $776,641,000 (December 31, 1982 — $744,139,000).

The Company has lines of credit totalling $200,000,000 with two Canadian chartered banks. These lines of credit allow the Company to borrow from the banks or to issue bankers acceptances and are also used to support commercial paper issued by the Company. These lines of credit are subject to annual review by the chartered banks.

The Company's First Mortgage Pipe Line Bonds are secured by a specific First Mortgage on substantially all of the Company's fixed assets, its gas purchase contracts, its gas sales contracts, 807,200 common shares of Westcoast Petroleum Ltd. and by a first floating charge on other assets and its undertakings.

Interest on long term debt for the year ended December 31, 1983 amounted to $88,219,000 (for the years ended December 31, 1982 — $81,380,000, December 31, 1981 — $67,399,000).

13. Income Taxes:

Income tax expense was $40,416,000 for the year ended December 31, 1983 reflecting an effective rate of 37.1% applied to income before income taxes, minority interest and extraordinary item (December 31, 1982 — $62,536,000 [45.5%], December 31, 1981 — $63,454,000 [47.3%]). The income tax expense varies from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates of approximately 50.2%, 51.1% and 51.6% respectively to income before income taxes, minority interest and extraordinary item for the following reasons:

Provision for Income Taxes	For the years ended December 31					
	1983		1982		1981	
	$000	**% of income before income taxes, minority interest and extraordinary item**	$000	% of income before income taxes and minority interest	$000	% of income before income taxes and minority interest
Federal and Provincial income tax rates applied to book income	**$ 54,703**	**50.2%**	$ 70,203	51.1%	$ 69,245	51.6%
Increase (decrease) in income taxes resulting from:						
Equity (non-taxable) portion of allowance for funds capitalized	**(823)**	**(0.7)**	(7,286)	(5.3)	(6,733)	(5.0)
Petroleum and natural gas activities	**(2,371)**	**(2.2)**	(743)	(0.5)	16	—
The adoption of the income taxes currently payable basis of accounting for income taxes on the Company's utility operations (Note 1):						
Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization	**(8,751)**	**(8.0)**	—	—	—	—
Other items deducted for income tax purposes in advance of accounting charges	**(1,824)**	**(1.7)**	—	—	—	—
Other	**(518)**	**(0.5)**	362	0.2	926	0.7
Provision for income taxes	**$ 40,416**	**37.1%**	$ 62,536	45.5%	$ 63,454	47.3%

Effective January 1, 1983, the Company has been directed by the National Energy Board to adopt the income taxes currently payable basis for its utility operations (Note 1), under which no provision is made for deferred income taxes which result from timing differences in recognition of income and expenses for income tax and financial statement purposes.

The 1982 deferred income taxes have been revised due to the reclassification of certain of the Company's capital assets for income tax purposes resulting in a revision of capital cost allowance claimed and a restatement of $16,138,000 of current income taxes to deferred taxes for 1982. The investment tax credit of $6,000,000 previously recorded for 1982 under Plant, Property and Equipment has also been reversed.

The sources of the timing differences and the income tax effects of each were as follows:

	For the years ended December 31		
	1983	1982	1981
		(restated) $000	
Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization	**$10,614**	$35,332	$34,420
Depletion and oil and gas exploration expenditures claimed for income tax purposes in excess of that recorded for accounting purposes	**5,192**	5,900	4,741
Other items deducted for income tax purposes in advance of accounting charges	**3,560**	14,490	18,394
Deferred income taxes	**$19,366**	$55,722	$57,555

As at December 31, 1983, the Company had unclaimed investment tax credits of $22,574,000 available to reduce future Federal income taxes payable. These credits expire as follows:

1984-$7,935,000	1985-$5,414,000	1986-$3,103,000
1987-$4,654,000	1988-$1,468,000	

14. Reconciliation of Generally Accepted Accounting Principles:

If generally accepted accounting principles used in the United States were followed, the effect on net income would be as follows:

	For the years ended December 31		
	1983	1982	1981
		(restated) $000	
Net income*	**$48,444**	$70,047	$65,426
Adjustment for translation of long term debt**	**(883)**	(1,413)	1,197
Full cost accounting***	**(8,500)**	—	—
Adjusted net income	**39,061**	68,634	66,623
Provision for dividends on preferred shares	**3,142**	3,142	3,142
Adjusted net income applicable to common shares	**$35,919**	$65,492	$63,481
Common stock — weighted average and common stock equivalents (000)	**40,743**	40,664	39,308
Per common share — primary*	**$ .88**	$1.61	$1.61

* Generally accepted accounting principles used in the United States require the extraordinary item described in Note 4 to be reported as a regular deduction from income.

** The Company translates long term debt payable in United States funds into Canadian dollars at exchange rates prevailing at the respective dates of issue. Generally accepted accounting principles used in the United States require the recognition of gains or losses resulting from translation of foreign debt at exchange rates prevailing at the end of the fiscal periods. However, since the Company is reimbursed for that portion of foreign exchange gains or losses on foreign debt repayments and foreign interest payments associated with the financing of its utility rate base and construction work in progress through cost of service, this portion has been excluded from the adjustment amounts.

*** Costs related to oil and gas properties located in the United States are being amortized on a straight-line basis at an annual rate of 20% until sufficient reserves are developed. If the Company accounted for depletion under procedures which apply in the United States, a reconciling item of $8,500,000 in 1983 would result as shown in the above table. This reconciling item would arise because under the United States Securities and Exchange Commission's full cost accounting rules, cost centres must be established on a country-by-country basis. Costs related to unproven exploration projects are not amortized unless and until it is apparent that a loss has been incurred.

Balance sheet items under generally accepted accounting principles used in the United States would be restated as follows:

	December 31	
	1983	1982
	$000	
Accumulated depreciation and depletion	**$546,522**	$469,467
Other deferred charges	**41,113**	38,980
Retained earnings	**224,082**	231,717
Long term debt	**776,641**	744,139

15. Westcoast Petroleum Ltd.:

During the year ended December 31, 1982, the Company, through its wholly owned subsidiary, Westcoast Transmission Holdings Ltd., acquired an additional 42% of the shares of Westcoast Petroleum Ltd., increasing the Company's percentage ownership in that company to 100%.

16. Commitments and Contingencies:

The Company is a party, along with Foothills Pipe Lines (Yukon) Ltd. and Nova, an Alberta Corporation, to an agreement with the Government of Canada requiring that, in the event the National Energy Board issues a certificate for the construction of the Dempster Link (Note 4), construction will commence as expeditiously as possible. In the event of default by the parties to the agreement, the agreement provides for payment of $50 million to the Government of Canada, the obligation for which is joint and several among the parties.

Due to the size, complexity and nature of the Company's operations, a number of lawsuits are pending at any point in time in which the Company may be the plaintiff or defendant. In the opinion of management, the ultimate resolution of any current lawsuits would not have a material effect on the Company's consolidated financial position or results of operations.

SUPPLEMENTARY INFORMATION ON THE EFFECTS OF CHANGING PRICES (Unaudited)

For 1983 and subsequent years, the Canadian Institute of Chartered Accountants has recommended that companies over a certain size provide with their Annual Reports to Shareholders supplementary information with respect to the effects on asset values and net earnings resulting from changing prices. Such supplementary information is sometimes referred to as accounting for inflation.

Inflationary price increases pose serious problems for all companies including regulated utilities, but the effect on the latter is somewhat different from the effect on a non-regulated company. Notwithstanding this fact, the Canadian Institute of Chartered Accountants did not differentiate between different categories of companies in its recommendation. Accordingly, the Company shows below the supplementary information called for by the Institute, but the reader should be aware that, in the Company's view, such supplementary information is of marginal usefulness only, and may indeed be confusing to readers not wholly conversant with the method of operating and the capital activities of a regulated company.

The primary purpose of the following unaudited supplementary information is to provide readers of the financial statements with information about the impact on the financial position and operating results of the Company due to changes in prices of specific goods and services employed in the Company's operations and of changes in the general purchasing power of the monetary unit in which transactions are measured. This unaudited supplementary information has been prepared in accordance with the guidelines established by the Canadian Institute of Chartered Accountants for Reporting the Effects of Changing Prices. The current cost financial data, however, should be used with caution as the prescribed rules and definitions are still experimental in nature and necessitate an element of subjectivity in the application of assumptions and estimates. Inflation-related information and price indexes available may not specifically reflect the Company's operating environment and the costs of actual asset construction and replacement. The current cost financial data presented also does not include a valuation of the Company's organization, human resources, expertise and other intangible assets including goodwill. The current cost information is prepared based on the most relevant and available sources of information to the Company selected on a reasonable basis in accordance with the above-mentioned guidelines. However, the disclosure of this current financial cost information should not be taken as an indication that the Company intends to replace the assets or that the costs represent the outlay that would be incurred if the assets were replaced.

Current cost amounts for the Company's plant, property and equipment and inventory are determined primarily by using engineering estimates, appropriate price indexes or reliable market prices. Major components of the above are valued as follows:

Pipeline facilities are valued using estimates based on the current cost required for the construction of identical facilities.

Process plants and compressor stations are valued using estimates based on the assumption that the assets would be replaced with facilities of like capacity employing current technology.

Oil and gas properties are valued using appropriate specific price indexes.

Current value for inventory was determined by using appropriate specific indexes or reliable market prices.

As detailed under Note 1 of the Notes to the Consolidated Financial Statements, the Company's utility activities operate under a gas purchase agreement with the British Columbia Petroleum Corporation and are regulated by the National Energy Board. Under the agreement, the Company is reimbursed for its cost of service which includes the depreciation expenses of the Company's utility assets (at historical cost), inventory consumed and, also a return on its utility rate base which includes the undepreciated portion of plant, property and equipment and inventory (at historical cost) related to its utility operations. The National Energy Board does not recognize replacement cost for accounting purposes or rate determination. The Company's net income from utility operations is, therefore, directly related to its actual investment in utility assets which would eventually be recovered through depreciation or consumption. The current worth of the amount of cash that can be recovered from the usage of these assets would approximate the amount recorded on a historical cost basis and should be used as the relevant measure for these assets.

Pacific Northern Gas Ltd., Foothills Pipe Lines (Yukon) Ltd., Foothills Pipe Lines (North B.C.) Ltd. and Westcoast Petroleum Ltd.'s pipeline operations are regulated by their respective regulatory bodies. While their regulatory methods and procedures might vary, the effect on the current cost of assets engaged in regulated operations of these companies will be like that of the Company. The current cost estimates on a consolidated basis are adjusted accordingly.

Schedule of Assets on a Current Cost Basis

	December 31	
	Current Cost	Historical Cost*
	$000	
1983		
Plant, property and equipment — net	**$3,245,610**	$1,363,651
Inventory	**31,239**	23,044
	3,276,849	1,386,695
Adjustment of utility assets to net recoverable amount	**1,787,522**	—
	$1,489,327	$1,386,695
Net assets	**$ 574,828**	$ 472,196
1982		
Plant, property and equipment — net	**$3,187,430**	$1,363,888
Inventory	**26,483**	22,608
	3,213,913	1,386,496
Adjustment of utility assets to net recoverable amount	**1,693,768**	—
	$1,520,145	$1,386,496
Net assets	**$ 631,273**	$ 470,182

*The 1982 comparative amounts have been restated in 1983 year-end dollars with the exception of utility related assets.

The current cost adjustment for depreciation and depletion resulted primarily from the current cost adjustments to the oil and gas properties and production facilities of Westcoast Petroleum Ltd. This adjustment to net income was, however, reduced by the financing adjustment which represented the portion of increased current cost depreciation and depletion expenses not attributable to the common shareholders as a result of debt financing.

The common shareholders' equity could also be interpreted to have gained in the portion of increases in current cost of plant, property and equipment and inventory that are financed by other means including debt and preferred shares. This financing adjustment based on changes in current cost of plant, property and equipment and inventory for 1983 amounted to $992,000. Additional gain in general purchasing power from having net monetary liabilities during 1983 in the amount of $1,771,000 can also be deemed to have occurred.

Consolidated Statements of Operations

	For the year ended December 31, 1983	
	Restated on the Current Cost Basis	As Reported
	$000	
Operating revenues	**$1,127,105**	$1,127,105
Operating revenue deductions		
Cost of gas sold	**701,819**	701,819
Operation and maintenance	**109,108**	109,108
Depreciation and depletion	**76,545**	70,645
Taxes other than income taxes	**52,693**	52,693
	940,165	934,265
Operating income	**186,940**	192,840
Other income and income deductions	**83,872**	83,872
Income before undernoted items	**103,068**	108,968
Income taxes	**40,416**	40,416
Minority interest	**3,017**	3,463
Income		
— on a current cost basis	**59,635**	
— on a historical cost basis		65,089
Extraordinary item, net of deferred income taxes (Note 4)	**16,645**	16,645
	42,990	48,444
Financing adjustment on current cost adjustments for depreciation and depletion	**806**	—
Net income	**43,796**	48,444
Provision for dividends on preferred shares	**3,142**	3,142
Net income applicable to common shares:		
Including extraordinary item		
— on a current cost basis	**$ 40,654**	
— on a historical cost basis		$ 45,302
Before extraordinary item		
— on a current cost basis	**$ 57,299**	
— on a historical cost basis		$ 61,947

Other Supplementary Information

	For the year ended December 31, 1983
	$000
Increase in the current cost amounts of inventory and plant, property and equipment	**$ 7,801**
Effect of general inflation	**16,666**
Excess of increase in general inflation over the increase in current cost amount	**$ 8,865**

SUPPLEMENTARY INFORMATION ON OIL AND GAS ACTIVITIES (Unaudited)

The following supplementary information pertains to Westcoast Petroleum Ltd.'s oil and gas activities:

(a) Costs Incurred

	For the years ended December 31		
	1983	1982	1981
		$000	
Property acquisition costs	**$ 5,318**	$ 7,613	$ 7,755
Exploration costs	**32,810**	24,160	13,607
Development costs	**10,424**	18,270	10,629
	48,552	50,043	31,991
Less petroleum incentive grants	**17,201**	13,065	4,140
	$31,351	$36,978	$27,851
Production expenses	**$ 5,014**	$ 4,608	$ 3,760
Depreciation and depletion	**9,660**	9,103	7,645

(b) Results from Oil and Gas Operations

	For the years ended December 31		
	1983	1982	1981
		$000	
Revenues, net of royalties	**$43,887**	$43,133	$29,449
Less:			
Production costs	**5,014**	4,608	3,760
Depreciation and depletion	**9,660**	9,103	7,645
Petroleum and Natural Gas Tax	**6,057**	6,319	3,192
Incremental Oil Revenue Tax	**—**	297	—
Alberta Royalty Tax Credit	**(4,000)**	(4,670)	(1,333)
	16,731	15,657	13,264
Operating income	**27,156**	27,476	16,185
Income taxes	**13,087**	13,164	8,794
Results of operations for oil and gas operations	**$14,069**	$14,312	$ 7,391

(c) Capitalized Costs

	December 31	
	1983	1982
	$000	
Property acquisition, exploration and development costs	**$286,635**	$255,281
Accumulated depreciation and depletion	**(61,254)**	(51,593)
	$225,381	$203,688

(d) Oil and Gas Reserves

Crude Oil and Liquids

	December 31		
	1983	1982	1981
	(thousands of barrels)		
Proved (developed and undeveloped):			
Beginning of year	**10,490**	7,386	7,311
Revisions of previous estimates	**364**	564	34
Discoveries and other additions	**846**	3,652	1,089
Production during the year	**(1,180)**	(1,112)	(1,048)
End of year	**10,520**	10,490	7,386
Proved developed:			
Beginning of year	**10,490**	7,386	7,311
End of year	**10,112**	10,490	7,386

Natural Gas

	December 31		
	1983	1982	1981
	(billions of cubic feet)		
Proved (developed and undeveloped):			
Beginning of year	**389.8**	387.9	361.3
Revisions of previous estimates	**2.1**	(12.8)	(3.0)
Discoveries and other additions	**13.9**	26.4	40.8
Production during the year	**(9.1)**	(11.7)	(11.2)
End of year	**396.7**	389.8	387.9
Proved developed:			
Beginning of year	**219.2**	206.5	194.0
End of year	**230.0**	219.2	206.5

The above reserves of crude oil and liquids, and natural gas are mainly located in Canada. The Company calculates reserves as net share to the Company but before deduction of royalties. This is the most meaningful comparison because in some cases royalty rates are revised with price changes and in some cases production is sold to government agencies at prices below fair market value and there is no royalty. Reserve estimates include only those reserves recoverable under existing economic and operating conditions and do not include reserves contained in untested zones or reserves available through enhanced recovery schemes where performance is not proven.

(e) Standardized Measure of Discounted Future Net Cash Flows and Changes therein from Proved Reserves

The following information is provided as required by Statement No. 69 issued by the Financial Accounting Standards Board in the United States.

The Company cautions that the calculation of the discounted future net cash flows from proved oil and gas reserves does not represent fair market value of the reserves nor future cash flows from production of the reserves. The values do not include the value of unproved exploratory properties and the value of probable reserves.

Standardized Measure of Discounted Future Cash Flows From Proved Oil and Gas Reserves

	December 31	
	1983	1982
	$000	
Estimated future cash inflows	**$1,114,122**	$986,430
Less:		
Estimated future production costs	**112,639**	109,898
Estimated future development costs	**75,351**	61,373
Estimated future Petroleum and Natural Gas Tax	**165,051**	152,588
Estimated future income taxes	**386,852**	316,221
Estimated future net cash flows	**374,229**	346,350
Less discount at 10% per annum for estimated timing of future net cash flows	**191,607**	182,311
Discounted future net cash flows	**$ 182,622**	$164,039

Changes in Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	For the years ended December 31	
	1983	1982
	$000	
Revisions to reserves proved in prior years:		
Revisions in quantity	**$ 5,704**	$ (2,066)
Changes in prices	**30,712**	31,862
Other	**608**	(18,490)
	37,024	11,306
Accretion of discount	**16,404**	12,007
Discoveries and extensions, net of related costs	**16,182**	61,019
Previously estimated development costs incurred during the year	**5,792**	5,782
Revenue, net of production costs and Petroleum and Natural Gas Tax from production	**(32,816)**	(32,206)
Net change in income taxes	**(24,003)**	(13,934)
Net change	**18,583**	43,974
Balance at beginning of year	**164,039**	120,065
Balance at end of year	**$182,622**	$164,039

Estimated future cash inflows are based on estimated future production volumes of proved reserves at prices in effect on January 1st of the following year. Estimated future production costs include field operating costs which are based on year-end costs but exclude depreciation and depletion, corporate overhead and interest costs. Future development costs represent estimated expenditures to be incurred to complete the development and production of the proved reserves based on year-end costs. Estimated Petroleum and Gas Revenue Tax is computed based on rates and legislation in effect at each year-end. Future income tax expense has been computed by applying year-end statutory rates, to the future estimated taxable income adjusted for the tax basis of the oil and gas properties. The prescribed discount rate of 10 percent was used in arriving at discounted net cash flow.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITIONS AND RESULTS OF OPERATIONS

Year Ended December 31, 1983

A substantial portion of the Company's operating cash flow was generated from its utility operations, which are subject to a gas purchase agreement with the British Columbia Petroleum Corporation and to National Energy Board regulation. Under the agreement, the Company recovers its operating expenses and a prescribed rate of return on its utility rate base assets. In 1983, consolidated funds generated from operations decreased by approximately 13% to $159 million. This reduction is primarily due to approximately $11 million arising out of the Company's adoption of the income taxes currently payable basis of accounting for and collection of income taxes from its pipeline operations and an increase in current income taxes payable of approximately $14 million.

The Company's funds generated from operations together with the proceeds received from an issue of $60 million 12½% Debentures, 1993 Series, were used to finance the Company's capital projects, debt retirement and dividend payments.

Foothills Pipe Lines (Yukon) Ltd. added to its long term bank indebtedness by approximately $49 million during 1983 in order to help finance the completion of the construction on the Eastern Leg of Phase I of the Alaska Highway Natural Gas Pipeline Project. Twelve million dollars of this additional financing together with $167 million from earlier financings were reflected in the Company's financial statements by way of proportionate consolidation. The Company will continue to contribute its share of the equity capital requirements for the project. The Company had no other material commitments on December 31, 1983.

The Company has lines of credit totalling $200 million with two Canadian chartered banks. These lines of credit allow the Company to borrow from the banks, issue bankers acceptances and support commercial paper issued by the Company. These lines of credit are subject to annual review by the chartered banks.

Operating revenues for 1983 decreased from 1982 due to a 4% reduction in volumes of gas sold and a 2% decline in the average price of gas sold, offset by a full year of operation of both the Western Leg (October 1981) and the Eastern Leg (September 1982) of Phase I of the Alaska Highway Natural Gas Pipeline Project. Cost of gas sold declined during 1983 primarily due to the lower volumes of gas sold. Operating and maintenance expenses increased over 1982 primarily due to higher operating and maintenance expenses pertaining to the Eastern Leg of Phase I of the Alaska Highway Natural Gas Pipeline Project.

Depreciation and depletion increased in 1983 primarily due to an increase in fixed assets. Taxes other than income taxes decreased during 1983 primarily due to reduced Federal Natural Gas taxes offset by increased property taxes.

The net income of the Company was not affected by the variances relating to the gas sales volumes and prices described above because of the gas purchase agreement with the British Columbia Petroleum Corporation.

Allowance for funds used during construction decreased primarily due to the cessation of recording an allowance for Phase II effective January 1, 1983 and completion of the Eastern Leg of Phase I of the Alaska Highway Natural Gas Pipeline Project. The Phase II recovery increased in 1983 which reflected a full year's recovery versus only four months' recovery in 1982.

Investment and other income decreased due to reduced gains on advance purchases of debt in advance of repayment requirements.

Interest on debt decreased slightly due to reduced net borrowings by Foothills Pipe Lines (Yukon) Ltd. offset by increased borrowings by the Company.

Other income deductions decreased compared to 1982 due to reduced write-offs of costs related to certain feasibility studies on projects not being proceeded with at this time.

Income taxes in 1983 decreased primarily as a result of the Company's adoption of the income taxes currently payable basis for its pipeline operations.

The extraordinary item represents a write-off of certain costs relating to Phase II of the Alaska Highway Natural Gas Pipeline Project and is detailed in Note 4 of the Consolidated Financial Statements.

The Company anticipates no unusual events or significant economic changes in the foreseeable future which will adversely affect income from continuing operations. As the Company's income from utility operations is based on the gas purchase agreement with the British Columbia Petroleum Corporation, changes in sales revenue from its utility operations due to any changes in the price of gas or volume fluctuations, as well as any effect of inflationary price changes on revenue and operating expenses, do not directly affect the Company's net income.

The effects on net income arising from the variances between generally accepted accounting principles used in Canada and the United States are outlined in Note 14 of the Consolidated Financial Statements.

Year Ended December 31, 1982

The 1982 financial results have been restated primarily to reflect a retroactive reclassification of approximately $16 million in current income taxes payable as the result of successful discussions with Revenue Canada on the income tax treatment of certain assets of the Company. The effect of this restatement increased cash flow from operations in 1982 but had no effect upon net income for 1982.

A substantial portion of the Company's operating cash flow was generated from its utility operations, which are subject to a gas purchase agreement with the British Columbia Petroleum Corporation and to National Energy Board regulations. Under the agreement, the Company recovers its operating expenses and a prescribed rate of return on its utility rate base assets. The restated 1982 consolidated funds generated from operations increased slightly over 1981 by approximately 6% to $183 million. This increase was primarily due to increased funds generated from operations from Phase I of the Alaska Highway Natural Gas Pipeline Project and from Westcoast Petroleum Ltd.

The Company's funds generated from operations together with the proceeds received from an issue of $50 million 16¾% Debentures, 1987 Series, were used to finance the Company's capital projects, the acquisition of additional shares in Westcoast Petroleum Ltd., which is now fully owned, the funding requirements for the Alaska Highway Natural Gas Pipeline Project and in meeting the Company's debt retirement and dividend payments.

During 1982, Pacific Northern Gas Ltd. issued $40 million in long term debt. These proceeds were used to finance its 1982 capital program and to repay bank borrowings of approximately $32 million.

Foothills Pipe Lines (Yukon) Ltd. added to its long term bank indebtedness by approximately $257 million during 1982 in order to help finance the completion of the construction on the Eastern Leg of Phase I of the Alaska Highway Natural Gas Pipeline Project. Seventy-four million dollars of this additional financing together with $93 million from earlier financings were reflected in the Company's financial statements by way of proportionate consolidation.

The Company has lines of credit totalling $200 million with two Canadian chartered banks. These lines of credit allow the Company to borrow from the banks, issue bankers acceptances and support commercial paper issued by the Company. These lines of credit are subject to annual review by the chartered banks.

Operating revenues for 1982 decreased from 1981 due to a 10% reduction in volumes of gas sold and a 3% decline in the average price of gas sold, offset by increased revenues from Westcoast Petroleum Ltd. and the commencement of operation of both the Western Leg (October 1981) and the Eastern Leg (September 1982) of Phase I of the Alaska Highway Natural Gas Pipeline Project. Cost of gas sold declined during 1982 due to the lower volumes of gas sold. Operating and maintenance expenses declined over 1982 primarily due to a higher recovery in 1981 of operating and maintenance expenses previously deferred.

Depreciation and depletion increased in 1982 primarily due to the commencement of depreciation for the fixed assets of Phase I of the Alaska Highway Natural Gas Pipeline Project. Taxes other than income taxes decreased during 1982 primarily due to the reduction of the Federal Natural Gas Tax rate for export sales to zero percent in September 1981. This reduction was partially offset by increased property taxes.

The net income of the Company was not affected by the variances relating to the gas sales volumes and prices described above because of the gas purchase agreement with the British Columbia Petroleum Corporation.

The Phase II recovery pertaining to certain costs of the Alaska Highway Natural Gas Pipeline commenced in September 1982. Investment and other income decreased due to reduced levels of temporary cash investments during 1982.

Interest on debt for 1982 increased due to increased borrowings by the Company, Pacific Northern Gas Ltd. and Foothills Pipe Lines (Yukon) Ltd.

Other income deductions for 1982 increased due to a $1.6 million write-off (after-tax) of costs related to certain feasibility studies on projects not being proceeded with at this time.

Year Ended December 31, 1981

A substantial portion of the Company's operating cash flow was generated from its utility operations, which are subject to a gas purchase agreement with the British Columbia Petroleum Corporation and to National Energy Board regulations. Under the agreement, the Company recovers its operating expenses and a prescribed rate of return on its utility rate base assets. In 1981, consolidated funds generated from operations increased by approximately 12% to $173 million. The Company's funds generated from operations were used to finance the Company's capital projects, debt retirement, dividend payments and the funding requirements for the Alaska Highway Natural Gas Pipeline Project.

Pacific Northern Gas Ltd. supplemented its funding requirements for its capital program for 1981 by term bank loans of approximately $32 million.

Foothills Pipe Lines (Yukon) Ltd. added to its long term bank indebtedness by approximately $262 million during 1981 for the construction of Phase I of the Alaska Highway Natural Gas Pipeline Project. Sixty-six million dollars of this additional financing together with $27 million of earlier financing was reflected in the Company's financial statements by way of proportionate consolidation.

The Company has lines of credit totalling $200 million with two Canadian chartered banks. These lines of credit allowed the Company to borrow from the banks and issue bankers acceptances. These lines of credit are subject to annual review by the chartered banks.

Operating revenues increased over 1980 due to the increase of 13% in average price of gas sold, offset by a decrease of 9% in the volume of gas sold. Operating and maintenance expenses exceeded 1980 by approximately 10% excluding the recovery of $11 million of operating and maintenance expenses previously deferred. This increase of 10% in operating and maintenance expenses was due to the expansion of the Company's facilities and increased maintenance. Increases in depreciation and depletion resulted from additions to depreciable assets during the year. Taxes other than income taxes increased primarily due to increases in property taxes and the introduction, effective November 1, 1980, of the Federal Natural Gas Tax.

The net income of the Company was not affected by the variances relating to the gas sales volumes and prices described above because of the gas purchase agreement with the British Columbia Petroleum Corporation.

Allowance for funds used during construction increased primarily due to increased construction activities on the Alaska Highway Natural Gas Pipeline Project.

Investment and other income in 1981 increased due to increased levels of temporary cash investments.

Interest on debt in 1981 increased due to increased borrowings by Pacific Northern Gas Ltd. and Foothills Pipe Lines (Yukon) Ltd.

Income taxes in 1981 increased due to higher earnings of the Company.

CONSOLIDATED QUARTERLY RESULTS (Unaudited)

1983	For the three months ended			
	March 31	June 30	Sept. 30	Dec. 31
		$000		
Operating revenues	$331,930	$178,048	$193,231	$423,896
Operating revenue deductions	282,240	130,650	145,609	375,766
Operating income	49,690	47,398	47,622	48,130
Other	21,833	22,345	22,157	21,000
Income before undernoted items	27,857	25,053	25,465	27,130
Income taxes	10,402	9,333	10,007	10,674
Income before extraordinary item	17,455	15,720	15,458	16,456
Extraordinary item	—	—	—	16,645
Net income	17,455	15,720	15,458	(189)
Provision for dividends on preferred shares	786	785	786	785
Net income applicable to common shares:				
Including extraordinary item	$ 16,669	$ 14,935	$ 14,672	$ (974)
Before extraordinary item	$ 16,669	$ 14,935	$ 14,672	$ 15,671
Per common share — basic:				
Including extraordinary item	$.41	$.37	$.36	$(.03)
Before extraordinary item	$.41	$.37	$.36	$ .38

CONSOLIDATED QUARTERLY RESULTS (Unaudited)

1982 (restated)	For the three months ended			
	March 31	June 30	Sept. 30	Dec. 31
	$000			
Operating revenues	$424,274	$215,591	$151,461	$365,625
Operating revenue deductions	378,490	171,169	100,228	310,970
Operating income	45,784	44,422	51,233	54,655
Other	9,045	12,283	18,822	23,361
Income before undernoted items	36,739	32,139	32,411	31,294
Income taxes	17,205	13,927	15,108	16,296
Net income	19,534	18,212	17,303	14,998
Provision for dividends on preferred shares	786	785	786	785
Net income applicable to common shares	$ 18,748	$ 17,427	$ 16,517	$ 14,213
Per common share — basic	$.46	$.43	$.41	$.35

SEGMENTED STATEMENTS OF OPERATIONS (Unaudited)

FOR THE YEARS ENDED DECEMBER 31

	Westcoast Transmission Company Limited and Utility Subsidiaries*	Westcoast Petroleum Ltd.	Foothills Pipe Lines (Yukon) Ltd.	Other Subsidiaries	Consolidated
			$000		
1983					
Operating revenues	**$ 985,504**	**$52,080**	**$49,157**	**$40,364**	**$1,127,105**
Operating revenue deductions	**874,788**	**23,854**	**14,006**	**21,617**	**934,265**
Operating income	**110,716**	**28,226**	**35,151**	**18,747**	**192,840**
Other income	**3,424**	**19**	**5,339**	**133**	**8,915**
	114,140	**28,245**	**40,490**	**18,880**	**201,755**
Income deductions	**60,644**	**3,147**	**20,662**	**8,334**	**92,787**
Income before undernoted items	**53,496**	**25,098**	**19,828**	**10,546**	**108,968**
Income taxes	**14,979**	**12,346**	**8,073**	**5,018**	**40,416**
Minority interest	**—**	**—**	**—**	**3,463**	**3,463**
	38,517	**12,752**	**11,755**	**2,065**	**65,089**
Extraordinary item	**—**	**—**	**16,645**	**—**	**16,645**
Net income	**$ 38,517**	**$12,752**	**$(4,890)**	**$ 2,065**	**$ 48,444**
1982 (restated)					
Operating revenues	$ 1,039,187	$ 52,630	$ 27,457	$ 37,677	$ 1,156,951
Operating revenue deductions	903,207	24,755	9,220	23,675	960,857
Operating income	135,980	27,875	18,237	14,002	196,094
Other income	7,057	50	27,574	1,623	36,304
	143,037	27,925	45,811	15,625	232,398
Income deductions	61,359	3,970	23,481	6,188	94,998
Income before undernoted items	81,678	23,955	22,330	9,437	137,400
Income taxes	41,672	12,220	4,184	4,460	62,536
Minority interest	—	1,722	—	3,095	4,817
Net income	$ 40,006	$ 10,013	$ 18,146	$ 1,882	$ 70,047
1981					
Operating revenues	$ 1,205,759	$ 38,587	$ 4,641	$ 21,343	$ 1,270,330
Operating revenue deductions	1,071,113	20,581	2,026	10,823	1,104,543
Operating income	134,646	18,006	2,615	10,520	165,787
Other income	8,602	740	27,284	952	37,578
	143,248	18,746	29,899	11,472	203,365
Income deductions	48,137	3,084	15,904	2,046	69,171
Income before undernoted items	95,111	15,662	13,995	9,426	134,194
Income taxes	48,836	8,933	584	5,101	63,454
Minority interest	—	2,806	—	2,508	5,314
Net income	$ 46,275	$ 3,923	$ 13,411	$ 1,817	$ 65,426

*Utility subsidiaries: Westcoast Transmission Company (Alberta) Ltd.
Westcoast Transmission Housing Ltd., wound up March 31, 1981

WESTCOAST TRANSMISSION COMPANY LIMITED
TEN-YEAR REVIEW

FOR THE YEARS ENDED DECEMBER 31 (Dollar amounts are in thousands except per share figures)

FINANCIAL		(restated)		
Operations:	**1983**	1982	1981	1980
Operating revenues	**$1,127,105**	$1,156,951	$1,270,330	$1,217,600
Operating income	**192,840**	196,094	165,787	146,948
Financial charges	**92,349**	92,417	69,674	53,230
Net income*	**65,089**	70,047	65,426	49,035
Dividends on preferred shares	**3,142**	3,142	3,142	3,165
Net income applicable to common shares*	**61,947**	66,905	62,284	45,870
Dividends on common shares	**42,352**	42,280	36,578	28,494
Cash flow from operations	**158,875**	183,268	172,699	154,931
Per Common Share:				
Net income — basic*	**1.52**	1.65	1.59	1.29
Dividends	**1.04**	1.04	.92	.80
Dividend payout ratio*	**68%**	63%	58%	62
Cash flow from operations	**3.90**	4.51	4.40	4.36
Assets:				
Plant, property and equipment	**1,901,673**	1,833,355	1,602,493	1,368,720
Accumulated depreciation and depletion	**538,022**	469,467	410,143	358,235
Net plant, property and equipment	**1,363,651**	1,363,888	1,192,350	1,010,485
Net additions to plant	**68,318**	230,862	233,773	145,661
Total assets	**1,719,052**	1,707,913	1,480,109	1,305,750
Rate Base and Return:				
Average utility rate base	**739,344**	747,803	742,780	706,156
Average return on utility rate base	**12.0%**	11.9%	11.4%	10.9
Average return on equity in utility rate base	**14.7%**	15.2%	15.4%	13.0
Capitalization:				
Long term debt	**732,421**	701,618	595,880	525,822
Preferred shareholders' equity	**36,966**	36,966	36,966	36,966
Common shareholders' equity	**472,196**	470,182	445,687	377,028
— per common share	**11.59**	11.56	10.97	10.42
Return on average common shareholders' equity*	**13.8%**	14.6%	15.1%	12.6
Capitalization Ratios:				
Long term debt	**59.0%**	58.0%	55.3%	56.0
Preferred shareholders' equity	**3.0%**	3.1%	3.4%	3.9
Common shareholders' equity	**38.0%**	38.9%	41.3%	40.1
STATISTICAL				
Total gas sales:				
Thousands of cubic metres	**6 782 851**	7 057 348	7 886 955	8 644 756
Millions of cubic feet	**239,441**	249,131	278,417	305,168
Average daily sales:				
Cubic metres	**18 583 153**	19 335 200	21 608 095	23 619 552
Thousands of cubic feet	**656,003**	682,551	762,786	833,792
Peak day sales:				
Cubic metres	**43 481 506**	40 696 398	40 016 303	39 436 900
Thousands of cubic feet	**1,534,939**	1,436,622	1,412,614	1,392,161
System sales capacity:				
Cubic metres per day	**42 548 400**	41 052 706	41 052 706	41 052 706
Thousands of cubic feet per day	**1,502,000**	1,449,200	1,449,200	1,449,200
Other:				
Kilometres of transmission pipelines	**2 331**	2 331	2 331	2 331
Miles of transmission pipelines	**1,448**	1,448	1,448	1,448
Kilometres of gathering pipelines	**2 104**	2 104	2 104	2 104
Miles of gathering pipelines	**1,307**	1,307	1,307	1,307
Compressor kilowatts	**356 757**	350 493	337 966	337 966
Compressor horsepower	**478,420**	470,020	453,220	453,220
Shares outstanding at year end**	**40,731,498**	40,689,998	40,614,998	36,189,581
Number of common shareholders	**11,745**	12,581	13,396	13,278
Employee person years utilization	**833**	870	825	770

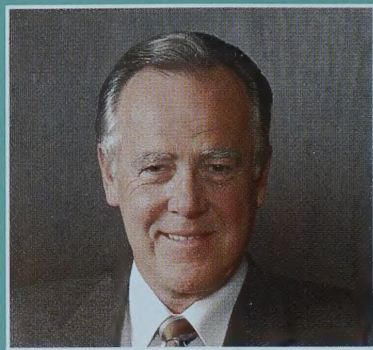
*Before 1983 extraordinary item of $16,645,000 ($ .41 per share)

**Financial information has been restated to give retroactive effect to the three-for-one common share split on May 12, 1978

1979	1978	1977	1976	1975	1974
$1,098,649	$ 843,902	$ 780,164	$ 579,276	$ 416,677	$ 266,600
99,323	79,337	74,978	67,930	53,913	49,974
36,908	29,548	27,398	23,945	25,934	27,680
49,870	46,359	43,562	39,769	33,019	26,731
3,399	3,400	3,400	3,400	3,400	1,559
46,471	42,959	40,162	36,369	29,619	25,172
28,122	23,652	21,674	19,798	17,654	11,275
104,977	84,594	81,460	75,125	54,184	46,844
1.33	1.25	1.21	1.12	.99	.97
.80	.69	.653	.612	.60	.433
60%	55%	54%	55%	61%	45%
3.00	2.46	2.45	2.32	1.81	1.80
1,223,059	1,070,259	932,821	882,394	736,752	699,954
318,127	284,143	254,218	227,669	167,632	149,212
904,932	786,116	678,603	654,725	569,120	550,742
152,800	137,438	50,427	36,977	36,798	46,731
1,148,313	963,781	824,311	768,150	675,189	664,999
607,821	546,579	529,758	516,738	499,092	493,404
10.9%	11.0%	11.0%	10.5%	10.0%	9.5%
14.0%	14.0%	14.5%	14.4%	14.2%	14.2%
417,734	376,393	310,456	317,275	308,037	367,105
39,604	40,000	40,000	40,000	40,000	40,000
352,353	327,089	297,509	269,183	247,670	190,668
9.95	9.44	8.84	8.26	7.72	7.33
13.7%	13.8%	14.2%	14.1%	13.5%	13.8%
51.6%	50.6%	47.9%	50.6%	51.7%	61.4%
4.9%	5.4%	6.2%	6.4%	6.7%	6.7%
43.5%	44.0%	45.9%	43.0%	41.6%	31.9%
10 859 747	9 757 496	10 467 364	9 791 490	10 005 393	10 261 958
383,359	344,449	369,508	345,649	353,200	362,257
29 752 732	26 732 869	28 677 710	26 752 727	27 412 029	28 114 928
1,050,299	943,696	1,012,351	944,397	967,671	992,484
39 829 100	38 774 354	37 395 270	32 972 331	33 265 722	33 681 688
1,406,006	1,368,772	1,320,089	1,163,955	1,174,312	1,188,996
37 704 354	36 996 159	36 996 159	36 996 159	36 996 159	36 996 159
1,331,000	1,306,000	1,306,000	1,306,000	1,306,000	1,306,000
2 294	2 253	2 253	2 214	2 214	2 211
1,425	1,400	1,400	1,376	1,376	1,374
1 968	1 935	1 593	1 548	1 395	1 278
1,223	1,203	990	962	867	794
337 966	337 966	333 492	333 492	333 492	329 017
453,220	453,220	447,220	447,220	447,220	441,220
35,407,614	34,662,834	33,651,045	32,604,651	32,089,857	26,020,200
12,660	12,496	9,870	9,677	9,768	9,525
714	634	568	522	531	537

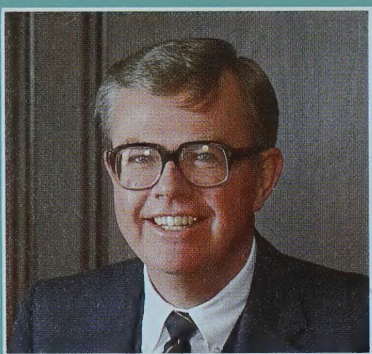
Directors

‡ * **Wilbert H. Hopper**
Chairman and Chief Executive Officer
Petro-Canada
A Crown energy corporation
Calgary, Alberta

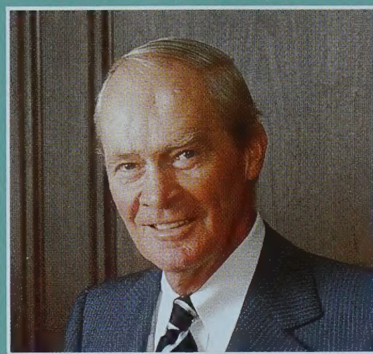


* **John Anderson**
President and Chief Executive Officer
Westcoast Transmission Company Limited
Vancouver, British Columbia

†‡ **James S. Byrn**
Chairman
Gulf Group Canada Limited
An investment holding company
Vancouver, British Columbia

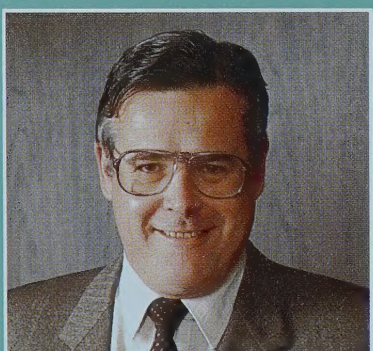


† * **David L. Helliwell**
President
Marin Investments Ltd.
An investment holding company
Vancouver, British Columbia

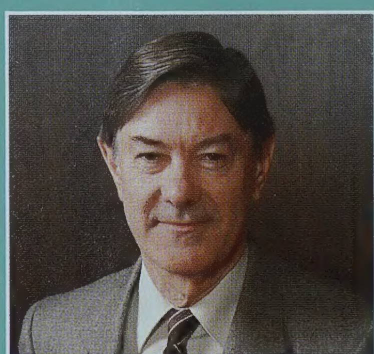


J. Taylor Kennedy
Retired
Montreal, Quebec

Edward M. Lakusta
President and Chief Operating Officer
Petro-Canada
A Crown energy corporation
Calgary, Alberta

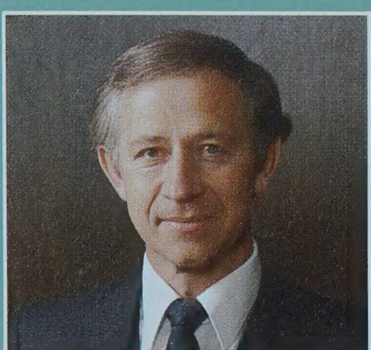


† **David P. O'Brien**
Senior Vice President,
Finance and Planning
Petro-Canada
A Crown energy corporation
Calgary, Alberta

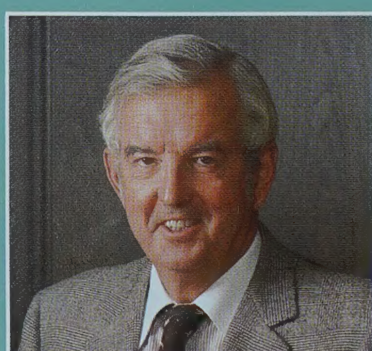


* **Derek H. Parkinson**
Senior Vice President
and Chief Financial Officer
Westcoast Transmission Company Limited
Vancouver, British Columbia

Edwin C. Phillips
Consultant
Vancouver, British Columbia



* **Arthur H. Willms**
Senior Vice President
Westcoast Transmission Company Limited
Vancouver, British Columbia



‡ **Charles N. W. Woodward**
Chairman of the Board
and Chief Executive Officer
Woodward Stores Limited
Retail merchants
Vancouver, British Columbia

* Executive Committee
† Audit Committee
‡ Compensation Committee

Frank M. McMahon
Chairman Emeritus of the Board
Hamilton, Bermuda

Corporate Information

Officers

Wilbert H. Hopper
Chairman

John Anderson
President and Chief Executive Officer

Derek H. Parkinson
Senior Vice President and Chief Financial Officer

Arthur H. Willms
Senior Vice President

William B. Caswell
Vice President, Process

Alton J. Green
Vice President, Administration

J. Edward Johnson
Vice President, Operations

John A. Kavanagh
Vice President, Engineering

Gordon W. Lade
Vice President, Secretary and General Counsel

Michael E. J. Phelps
Vice President, Strategic Planning

Wayne N. Collett
Treasurer

John H. Podmore
Comptroller

Philip G. Griffin
Associate General Counsel and
Assistant Secretary

Joachim W. Castelsky
Assistant Treasurer

Registrars

Common Shares
THE CANADA TRUST COMPANY —
Vancouver, B.C., Calgary, Alta., Regina, Sask., Toronto, Ont., Montreal, P.Q.
REGISTRAR AND TRANSFER COMPANY —
Cranford, New Jersey

Preferred Shares
CANADA PERMANENT TRUST COMPANY —
Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

Bonds
MONTREAL TRUST COMPANY —
Vancouver, B.C., Calgary, Alta., Toronto, Ont., Montreal, P.Q. (Series E Bonds are transferable at the Montreal Trust Company Branch in Winnipeg, Man.)

Debentures
7½% First Series Debentures
CANADA PERMANENT TRUST COMPANY —
Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

Other Series Debentures
THE CANADA TRUST COMPANY —
Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

Subordinate Debentures
CITIBANK, N.A. — New York, N.Y.
MONTREAL TRUST COMPANY (co-registrar) —
Vancouver, B.C., Calgary, Alta., Toronto, Ont., Montreal, P.Q.

Transfer Agents

Common Shares
MONTREAL TRUST COMPANY —
Vancouver, B.C., Calgary, Alta., Regina, Sask., Toronto, Ont., Montreal P.Q.
REGISTRAR AND TRANSFER COMPANY —
Cranford, New Jersey

Preferred Shares
THE CANADA TRUST COMPANY —
Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

Auditors
Clarkson Gordon
P.O. Box 10101, Pacific Centre
700 West Georgia Street, Vancouver, B.C.

Stock Exchanges
Listed on the Toronto, Montreal and Vancouver Stock Exchanges in Canada and the New York and Pacific Stock Exchanges in the United States.

Stock Symbol — WTC

Offices
1333 West Georgia Street, Vancouver, B.C. V6E 3K9
140 - 4th Avenue S.W., Calgary, Alberta T2P 3N3

Stock Market Price Ranges

(Common Shares)	New York		Toronto	
	Low	High	Low	High
	(United States Dollars)		(Canadian Dollars)	
January-March 1982	9⅞	11⅝	11¾	14⅜
April-June 1982	9⅛	11½	11⅝	14⅛
July-September 1982	9	11½	11¾	14⅜
October-December 1982	10¾	12⅞	13⅜	15½
January-March 1983	11	12½	13⅜	15¼
April-June 1983	10⅞	12⅛	13½	15
July-September 1983	10⅝	12½	13¼	15⅜
October-December 1983	12	12½	14⅞	15¾

Earnings and Dividends Paid*

(Common Shares)	1983		1982	
	Earnings	**Dividends**	Earnings	Dividends
January-March	**$ .41**	**$ .26**	$ .46	$ .26
April-June	**.37**	**.26**	.43	.26
July-September	**.36**	**.26**	.41	.26
October-December	**.38****	**.26**	.35	.26
	$1.52**	**$1.04**	$1.65	$1.04

*A resident of the United States receiving investment income generated in Canada is subject to withholding tax provisions under the Canadian Income Tax Act and the Canada-United States Tax Convention, 1943. With certain exceptions, dividends paid by the Company are subject to a withholding tax at a rate of 15%.

**Before extraordinary item of $ .41.

DESIGNED AND LITHO'D BY PRICE PRINTING LTD., VANCOUVER, CANADA

Westcoast Transmission Company Limited
1333 West Georgia Street, Vancouver, British Columbia V6E 3K9